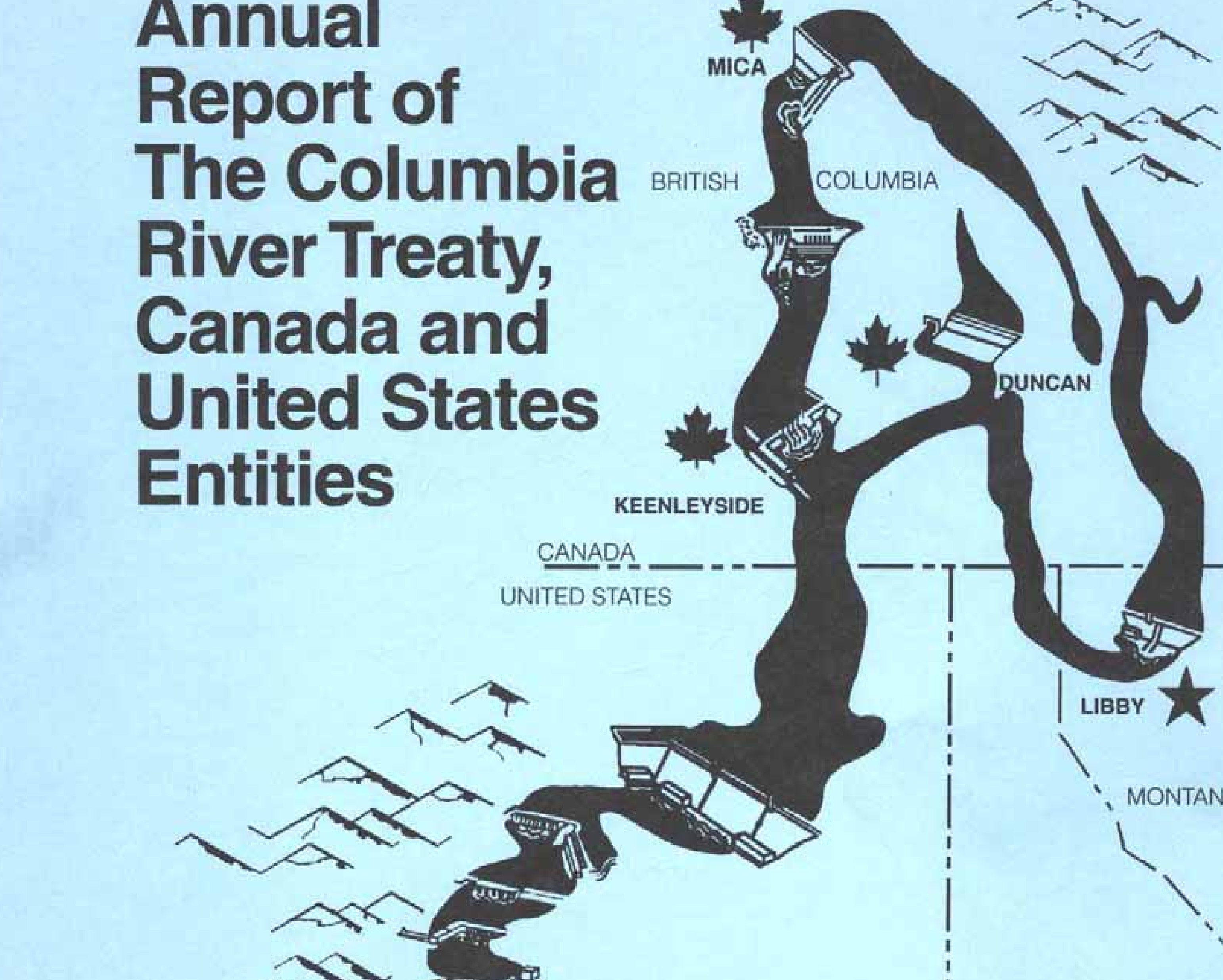
Annual Report of The Columbia River Treaty, Canada and United States Entities



1 October 2000 through
30 September 2001

November 2001

ANNUAL REPORT OF
THE COLUMBIA RIVER TREATY
CANADIAN AND UNITED STATES ENTITIES

FOR THE PERIOD
1 OCTOBER 2000 – 30 SEPTEMBER 2001

Executive Summary

General

The Canadian Treaty projects, Mica, Duncan, and Arrow were operated during the reporting period according to the 2000-01 and 2001-02 Detailed Operating Plans (DOP), the October 1999 Flood Control Operating Plan, and several supplemental operating agreements described below. Throughout the year, Libby was operated according to the 1999 Flood Control Operating Plan and the Libby Coordination Agreement (LCA) of February 2000. Through December 2000, Libby was operated for power purposes according to the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER). Both the U.S. Fish and Wildlife Service (USFWS) and the U.S. National Marine Fisheries Service (NMFS) developed new Biological Opinions dated 21 December 2000. Because of low water supply, Libby did not operate to specific flow for sturgeon in accordance with the USFWS Biological Opinion.

Figure 1: The Columbia River Treaty celebrated a forty year anniversary. The Treaty was signed by Prime Minister Diefenbaker and President Eisenhower on 17 January, 1961 as shown in the historic photograph above.

Entity Agreements

Agreements approved by the Entities during the period of this report include:

- Columbia River Treaty Entity Agreement on the DOP for Columbia River Storage for 1 August 2001, through 31 July 2002, signed 13 July 2001.
- Columbia River Treaty Entity Agreement on the Assured Operating Plan (AOP) and Determinations of Downstream Power Benefits (DDPB) for Operating Year 2005-06, signed 22 August 2001.

Operating Committee Agreements

Agreements approved by the Operating Committee include:

- Columbia River Treaty Operating Committee Agreement on Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning for the Period 1 September 2000 through 30 April 2001, signed 23 August 2000 (effective during this Water Year (WY) but signed in the previous WY).
- Agreement on Implementation of the Arrow Local Method for Canadian Treaty Storage for Operating Year 2000-01, among the Columbia River Treaty Operating Committee, the Bonneville Power Administration (BPA), and the British Columbia Hydro and Power Authority (B.C. Hydro), signed 29 December 2000.
- Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Nonpower Uses for 1 January through 31 July 2001, signed 30 November 2000.
- Agreement for Optimal Balancing of Storage between Arrow and Libby Reservoirs for the period 13 February 2001 through 3 April 2001, among the Columbia River Treaty Operating Committee, the BPA, and the B.C. Hydro, signed 8 May 2001.
- Columbia River Treaty Operating Committee Agreement on Operation of Summer Treaty Storage for 1 August 2001 through 31 March 2002, signed 18 July 2001.

System Operation

Under the 2000-01 DOP, the Coordinated System operation is modeled similar to AOP, without updated loads and U.S. fishery requirements. The Coordinated System operation under the DOP was to draft well below the Operating Rule Curve from 16 August 2000 to 31 July 2001.

The 1 January 2001 water supply forecast for the Columbia River at The Dalles (January-July) was 99.17 cubic kilometers (km^3) (80.4 million acre-feet (Maf)), or 76 percent of the 1961-90 average. Precipitation was very low through March, when monthly average precipitation spiked in April, sagging in May and rising to near normal in June and July. The water supply gradually declined over the period, finally leveling off in June and July. The unregulated runoff from January through July was 71.79 km^3 (58.2 Maf) at The Dalles, only 55 percent of the 1961-90 average. The actual unregulated runoff during the August through July operating year at The Dalles was the lowest in the 1929 - 2001 period of record at 101.9 km3 (82.6 Maf). The actual unregulated runoff during the January through July period at The Dalles was the second lowest in the 1929 - 2001 period of record at 71.8 km3 (58.2 Maf). The runoff in 2001 was about average in terms of timing, with the peak unregulated flow at The Dalles occurring in late May. The observed peak unregulated flow at The Dalles was 9,237 cubic meters per second (m^3/s) (326,800 cubic feet per second (cfs)) on 30 May 2001.

The Columbia River was operated to meet chum needs below Bonneville Dam and meet power demands from November 2000 through 16 March 2001. During this time, the Regional Executives of Federal, state and tribal agencies were active in setting operating priorities and criteria. By April the operating strategy was shifted to refilling storage projects as much as possible, where Dworshak was the top priority for refill by 30 June 2001. Although Dworshak was a priority for refill, none of the Federal projects refilled by 30 June because of low natural inflow. During July and August of 2001, the Federal reservoirs drafted to the summer draft limits recommended in the National Marine Fisheries Service 2000 Biological Opinion. As low flow continued into September 2001, the Federal reservoirs operated to meet winter power reliability needs for the upcoming season.

Canadian Entitlement

From 1 August 2000 through 31 July 2001, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Duncan and Arrow reservoirs to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. The amount returned, not including transmission losses and scheduling adjustments, was 277.4 average megawatts (aMW) at rates up to 793.7 MW. No Entitlement power was disposed directly in the U.S. during 1 August 2000 through 31 July 2001, as was allowed by the 29 March 1999 Agreements on "Aspects of the Delivery of the Canadian Entitlement for April 1, 1998 through September 15, 2024" and "Disposals of the Canadian Entitlement within the U.S. for April 1, 1998 through September 15, 2024." During the period of August 2001 through September 2001, the amount returned, not including transmission losses and scheduling adjustments, was 292.1 aMW at rates up to 782.6 MW.

Treaty Project Operation

The Canadian Treaty projects, Duncan, Mica and Arrow, were operated throughout the year in accordance with the 2000-01 Detailed Operating Plan, the October 1999 Flood Control Operating Plan, and the various Operating Committee Agreements. The Libby reservoir was operated in accordance with the 1999 Flood Control Operating Plan and the Libby Coordination Agreement.

The Mica Treaty storage account was 8.14 km^3 (6.6 Maf) on 31 July 2000 and with continued refill reached 8.63 km^3 (7.0 Maf) or 100 percent full storage on 15 August 2000. The actual reservoir elevation reached a maximum of 749.17 meters (m) (2457.9 feet) (5.21 m, or 17.1 feet below full) on 14 August 2000. By 31 December 2000, Treaty storage was drafted to 5.30 km^3 (4.3 Maf), and the observed reservoir level had dropped to elevation 733.23 m (2405.6 feet). The reservoir reached its lowest level for the 2000-2001 Water Year, elevation 714.76 m (2345.0 feet), on 26 April 2001. Treaty storage reached the lowest level for the year on 11 May 2001 at 0.025 km^3 (0.02 Maf) below empty. From then on, Mica Treaty storage refilled reaching 5.80 km^3 (4.7 Maf), on 24 August 2001. The maximum reservoir level for 2001 was elevation 742.13 m (2434.8 feet) (12.25 m, or 40.2 feet below full) on 3 September 2001.

The Arrow Treaty storage account was 8.63 km^3 (7.0 Maf) or 99 percent full, on 31 July 2000. The actual reservoir elevation reached a maximum of 440.10 m (1443.9 feet) on 26 July 2000. The reservoir was drafted to elevation 432.27 m (1418.2 feet) by 31 December 2000 with a Treaty storage of 4.81 km^3 (3.9 Maf), or 55 percent of full. Arrow Reservoir reached its lowest level of the year at elevation 422.18 m (1385.1 feet) on 22 May 2001. Arrow Treaty storage reached its annual minimum on 10 May 2001 at 1.00 km^3 (0.81 Maf), or 11 percent of full. During the period 24 December 2000 to 22 January 2001, Arrow outflows were held at 1076.04 m^3/s (38,000 cfs) to maintain lower river levels during the whitefish spawning period. During April and May 2001, outflows were held between 849.50 m^3/s (30,000 cfs) and 991.09 m^3/s (35,000 cfs) to ensure successful rainbow trout spawning immediately below Arrow, at water levels that could be maintained until hatch. The reservoir reached its highest level on 3 August 2001 at elevation 430.41 m (1412.1 feet) with the Treaty storage content reaching 6.54 km^3 (5.3 Maf) or 74 percent full, on 19 August 2001.

Duncan reservoir elevation on 31 July 2000 was at the full pool elevation of 576.68 m (1892.0 feet). During September through December, Duncan was used to support the Kootenay Lake levels and increase Kootenay River flows. By 31 December 2000, the reservoir had drafted to 547.30 m (1795.6 feet), 0.43 m, or 1.4 feet above empty pool elevation. Minimum release during May and July 2001 allowed the reservoir to refill to elevation 571.71 m (1875.7 feet) on 30 July 2001, 4.97 m or 16.3 feet below full pool elevation of 576.68 m (1892.0 feet). In August and September 2001, Duncan reservoir was again drafted to supplement flow into Kootenay Lake.

Columbia Basin Map

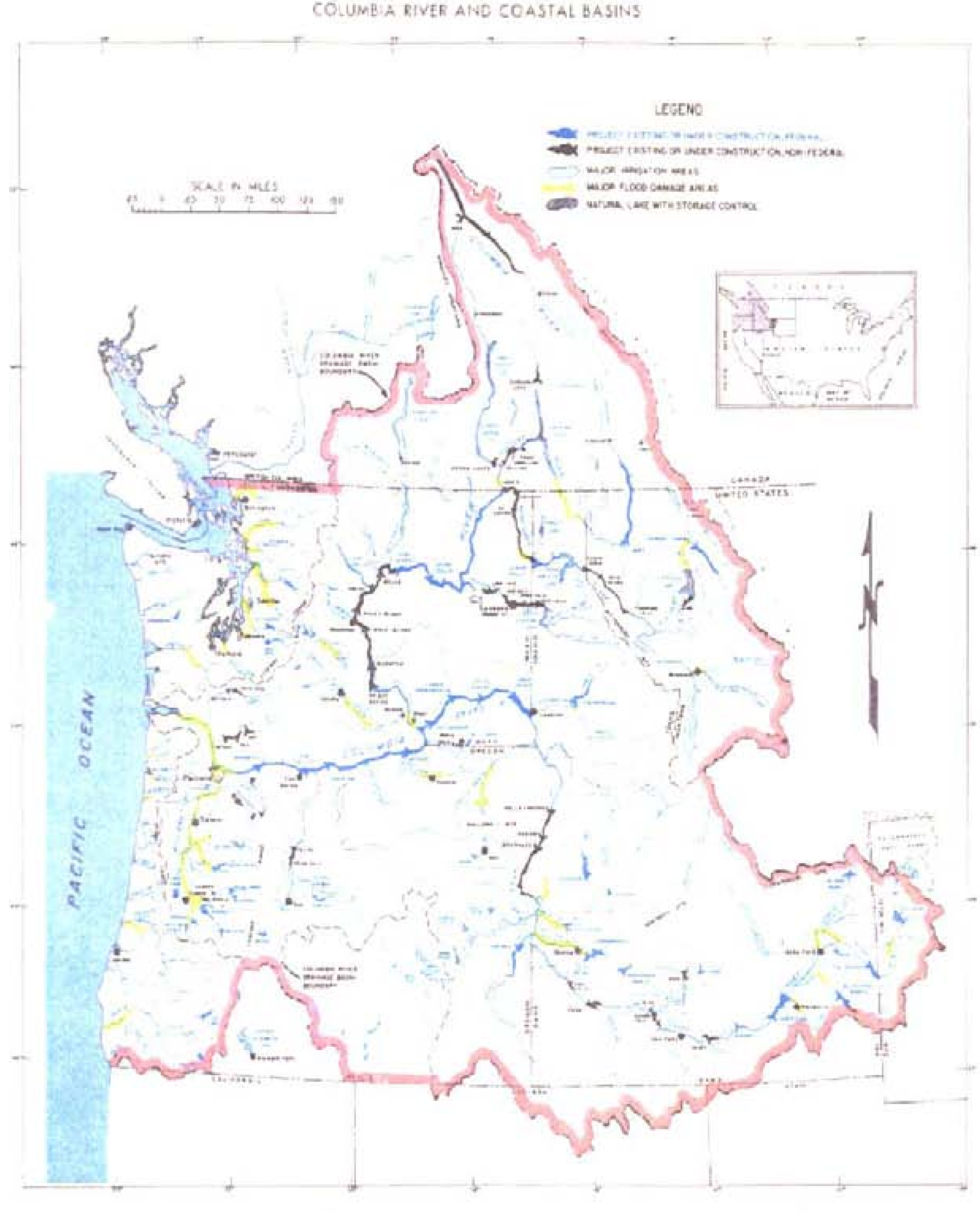


Figure 2

2001 Report of the Columbia River Treaty Entities
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2001 Report of The Columbia River Treaty Entities
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ACRONYMS

AER -	Actual Energy Regulation
aMW -	Average Megawatts
AOP -	Assured Operating Plan
B.C. Hydro -	British Columbia Hydro and Power Authority
BiOp -	Biological Opinions
BPA -	Bonneville Power Administration
CEEA -	Canadian Entitlement Exchange Agreement
CEPA -	Canadian Entitlement Purchase Agreement
cfs -	Cubic feet per second
CRC -	Critical Rule Curve
CRT -	Columbia River Treaty
CRTOC -	Columbia River Treaty Operating Committee
CSPE -	Columbia Storage Power Exchange
DDPB -	Determinations of Downstream Power Benefits
DOP -	Detailed Operating Plan
FCOP -	Flood Control Operating Plans
FPC -	Fish Passage Center
FRO -	Fall Runoff
hm^3	Cubic hectometers
ICF -	Initial Controlled Flow
IJC -	International Joint Commission
Km^3 -	Cubic Kilometers
ksfd	Thousand second-foot-days
LCA -	Libby Coordination Agreement
LOP	Libby Operating Plan
m	Meter
m^3/s -	Cubic meters per second
Maf -	Million acre feet
MW	Mega Watt
NERC -	North American Electric Reliability Council
NMFS -	National Marine Fisheries Service
NTSA -	Non Treaty Storage Agreement
ORC -	Operating Rule Curve
PEB -	Permanent Engineering Board
PEBCOM -	PEB Engineering committee
PNCA -	Pacific Northwest Coordination Agreement
PNW -	Pacific North West
STS -	Summer Treaty Storage Agreement
TMT -	Technical Management Team
TSR -	Treaty Storage Regulation
U.S.	United States
USACE -	U.S. Army Corps of Engineers
USFWS -	U.S. Fish and Wildlife Service
VRC -	Variable Rule Curve
WY -	Water Year

I Introduction

This annual Columbia River Treaty Entity Report is for the 2001 Water Year, 1 October 2000 through 30 September 2001. It includes information on the operation of Mica, Arrow, Duncan, and Libby reservoirs during that period with additional information covering the reservoir system operating year, 1 August 2000 through 31 July 2001. The power and flood control effects downstream in Canada and the United States are described. This report is the thirty-fifth of a series of annual reports covering the period since the ratification of the Columbia River Treaty in September 1964.

Duncan, Arrow, and Mica reservoirs in Canada and Libby reservoir in the United States of America were constructed under the provisions of the Columbia River Treaty of January 1961. Treaty storage in Canada (Canadian storage) is operated for the purposes of flood control and increasing hydroelectric power generation in Canada and the United States of America. In 1964, the Canadian and the United States governments each designated an Entity to formulate and carry out the operating arrangements necessary to implement the Treaty. The Canadian Entity is the B.C. Hydro. The United States Entity is the BPA and the Division Engineer of the Northwestern Division, U.S. Army Corps of Engineers (USACE).

The following is a summary of key features of the Treaty and related documents:

1. Canada is to provide 19.12 km^3 (15.5 Maf) of usable storage. This has been accomplished with 8.63 km^3 (7.0 Maf) in Mica, 8.78 km^3 (7.1 Maf) in Arrow and 1.73 km^3 (1.4 Maf) in Duncan.

2. For the purpose of computing downstream power benefits the U.S. base system hydroelectric facilities will be operated in a manner that makes the most effective use of the improved streamflow resulting from operation of the Canadian storage.

3. The U.S. and Canada are to share equally the downstream power benefits generated in the U.S. resulting from operation of the Canadian storage.

4. The U.S. paid Canada a lump sum of the $64.4 million (U.S.) for one half of the present worth of expected future flood control benefits in the U.S. resulting from operation of the Canadian storage.

5. The U.S. has the option of requesting the evacuation of additional flood control space above that specified in the Treaty, for a payment of $1.875 million (U.S.) for each of the first four requests for this "on-call" storage.

6. The U.S. had the option (which it exercised) to construct Libby Dam with a reservoir that extends 67.6 kilometers (42 miles) into Canada and for which Canada agreed to make the land available.

7. Both Canada and the United States have the right to make diversions of water for consumptive uses. In addition, since September 1984 Canada has had the option of making for power purposes specific diversions of the Kootenay River into the headwaters of the Columbia River.

8. Differences arising under the Treaty which cannot be resolved by the two countries may be referred to either the International Joint Commission (IJC) or to arbitration by an appropriate tribunal.

9. The Treaty shall remain in force for at least 60 years from its date of ratification, 16 September 1964.

10. In the Canadian Entitlement Purchase Agreement of 13 August 1964, Canada sold its entitlement to downstream power benefits to the United States for 30 years beginning at Duncan on 1 April 1968, at Arrow on 1 April 1969, and at Mica on 1 April 1973.

11. Canada and the U.S. are each to appoint Entities to implement Treaty provisions and are to jointly appoint a Permanent Engineering Board (PEB) to review and report on operations under the Treaty.

II Treaty Organization

Entities

There was one meeting of the Columbia River Treaty Entities (including the Canadian and U.S. Entities and Entity Coordinators) during the year on the morning of 21 February 2001 in Vancouver, BC. The members of the two Entities at the end of the period of this report were:

UNITED STATES ENTITY
Mr. Stephen J. Wright, Chairman
Acting Administrator & Chief Executive Officer
Bonneville Power Administration
Department of Energy
Portland, Oregon

Colonel David A. Fastabend, Member
Division Engineer
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY
Mr. Larry Bell, Chair
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

Mr. Wright replaced Ms. Judith A. Johansen on 17 November 2000; Colonel David A. Fastabend replaced Brigadier General Carl A. Strock on 22 August 2001; Mr. Bell replaced Mr. Robert Fairweather on 9 August 2001 as Chair of B.C. Hydro and on 18 October 2001 as the Canadian Entity, who in turn replaced Mr. Brian R.D. Smith on 4 June 2001.

The Entities have appointed Coordinators, Secretaries and two joint standing committees to assist in Treaty implementation activities that are described in subsequent paragraphs. The primary duties and responsibilities of the Entities as specified in the Treaty and related documents are to:

1. Plan and exchange information relating to facilities used to obtain the benefits contemplated by the Treaty.

2. Calculate and arrange for delivery of hydroelectric power to which Canada is entitled and the amounts payable to the U.S. for standby transmission services (no longer in effect).

3. Operate a Hydrometeorological system.

4. Assist and cooperate with the Permanent Engineering Board in the discharge of its functions.

5. Prepare hydroelectric and flood control operating plans for the use of Canadian storage.

6. Prepare and implement detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under assured operating plans.

Additionally, the Treaty provides that the two governments by an exchange of diplomatic notes may empower or charge the Entities with any other matter coming within the scope of the Treaty.

Entity Coordinators & Secretaries

The Entities have appointed Coordinators from members of their respective staffs to help manage and coordinate Treaty related work, and Secretaries to serve as information focal points on all Treaty matters within their organizations.

The members are:

UNITED STATES ENTITY COORDINATORS
Gregory K. Delwiche, Coordinator
Vice President, Generation Supply
Bonneville Power Administration
Portland, Oregon

Michael B. White, Coordinator
Director, Civil Works & Management
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY COORDINATOR
Kenneth R. Spafford, Coordinator
Principal Engineer, Resource Management,
Resource Management, B.C. Hydro
Burnaby, British Columbia

UNITED STATES ENTITY SECRETARY
Dr. Anthony G. White
Regional Coordination
Power and Operations Planning
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY SECRETARY
Douglas A. Robinson
Resource Management
Power Supply
B.C. Hydro and Power Authority
Burnaby, British Columbia

Mr. Spafford replaced Mr. Timothy J. Newton on 1 October 2000.

Columbia River Treaty Operating Committee

The Operating Committee was established in September 1968 by the Entities, and is responsible for preparing and implementing operating plans as required by the Columbia River Treaty, making studies and otherwise assisting the Entities as needed. The Operating Committee consists of eight members as follows:

UNITED STATES SECTION
Richard M. Pendergrass, BPA, Co-Chair
William E. Branch, USACE, Co-Chair
Cynthia A. Henriksen, USACE
John M. Hyde, BPA

CANADIAN SECTION
Ralph D. Legge, B.C. Hydro, Chair
Kelvin Ketchum, B.C. Hydro
Dr. Thomas K. Siu, B.C. Hydro
Allan Woo, B.C. Hydro

Mr. Woo replaced Mr. Kenneth R. Spafford on 1 October 2000.

The Operating Committee met six times during the reporting period to exchange information, approve work plans, and discuss and agree on operating plans and issues. The meetings were held every other month alternating between Canada and the U.S. During the period covered by this report, the Operating Committee coordinated the operation of the Treaty storage in accordance with the current hydroelectric and flood control operating plans, completed the 2005-06 Assured Operating Plan (AOP) and Determination of Downstream Power Benefits (DDPB), completed the 1 August 2001 through 31 July 2002 DOP, updated the Libby Operating Plan (LOP) component of the LCA, and completed several supplemental operating agreements. These aspects of the Committee's work are described in following sections of this report, which have been prepared by the Committee with the assistance of others.

The Operating Committee continued studies analyzing the proposed Variable Q (flow) Adjustments to Libby's flood control rule curves and the potential for increasing summer outflows from Canadian storage for U.S. flow augmentation. The Operating Committee continued to explore alternative methods for simplifying the extensive procedures and studies currently used to prepare the AOP/DDPB. In order to assure correct delivery of the Canadian Entitlement, the Committee monitored and updated scheduling procedures and loss calculations. In accordance with the 1988 Entity Agreements on Principles and Procedures, the Committee assisted efforts to develop updated irrigation depletion estimates used to adjust historic stream flows for the AOP/SSPB studies.

Figure 3: Operating Committee at the 19 July 2001 tour of Keenleyside Dam

Operating Committee at the 19 July 2001 tour of Keenleyside Dam
Pictured from left to right: Alan Woo (B.C. Hydro Member), Cindy Henriksen (USACE Member), John Hyde (BPA Member), William Branch (USACE Co-Chair), Kelvin Ketchum (B.C. Hydro Member), Ralph Legge (B.C. Hydro Chair), Anthony White (U.S. Entity Secretary), Rick Pendergrass (BPA Chair), Douglas Robinson (Canadian Entity Secretary), Thomas Siu (B.C. Hydro Member).

Columbia River Treaty Hydrometeorological Committee

The Hydrometeorological Committee was established in September 1968 by the Entities and is responsible for planning and monitoring the operation of data facilities in accord with the Treaty and otherwise assisting the Entities as needed. The Committee consists of four members as follows:

UNITED STATES SECTION	CANADIAN SECTION
Nancy L. Stephan, BPA Co-Chair	Eric Weiss, B.C. Hydro, Chair
A. Rudder Turner, USACE, Co-Chair	Wuben Luo, B.C. Hydro, Member

Mr. Luo was appointed to replace Mr. Don Druce on 1 October 2000; Mr. Turner was appointed to replace on an interim basis Mr. Peter Brooks on 17 July 2001.

To accommodate the issues this year, the Committee met three times and engaged in several conference calls in order to accomplish its work. The first meeting was held on 9 November 2000.

The meeting was a continuation of previous discussions about what defined a treaty station. Each section brought a station listing with sites that were to be considered treaty stations. The size and complexity of the station list created further discussion as to how, where, and by whom this listing was to be maintained.

The Committee again met on 17 January 2001. The purpose was to continue the discussion of treaty stations and review a paper Eric Weiss had prepared for the PEB. The paper contained proposed changes and future updates of the Committee documents, covering issues ranging from Treaty Station definitions to data exchange and communication. After lengthy discussion, an overview of the results was presented at the Operating Committee meeting the next day in order to receive comments and suggestions for proceeding with the paper.

At the PEB/Entities' meeting on 21 February 2001, Nancy Stephan and Eric Weiss presented a final report entitled "Proposed Strategy for Future Updates of Committee Documents". In summary, the Hydromet Committee proposed to:

- Consider a hydromet station as Treaty / Support if the station is used to monitor, plan, and operate Treaty projects.
- Communicate with data collection agencies each year to remind them of the Committee's desire to be informed about changes in network status associated with the Columbia River basin.
- Take steps to ensure that monitoring, planning, and operations of Treaty facilities would not be detrimentally affected by proposed changes to the hydromet network.
- Regularly review existing and proposed models used for Columbia River Treaty (CRT) planning studies and operations, to assess hydromet data requirements.
- Recommend to the Columbia River Treaty Operating Committee (CRTOC), preferred daily and seasonal forecasting models for CRT operations.
- Revise the format of future Hydromet Committee documents to:
- Re-iterate the Committee's process for responding to proposed changes to the hydromet network.
- Document any network changes proposed by data collection agencies and hydroelectric utilities that would potentially affect Treaty monitoring, planning, and operations.
- Describe the committee response to any proposed changes to the network. The outcome or status of each proposed change would be documented, but complete listings of Treaty and Support stations would no longer be provided.

- Describe current data communication systems.
- Document data-exchange plans between the Entities, including the frequency of data measurement and communications.

Following the 21 February 2001, meeting, the Treaty Coordinators composed a letter to the PEB requesting approval of the Hydromet Committee's proposed changes. The Hydromet Committee is currently waiting to hear the PEB's decision. Until then, the Hydromet Committee is already planning for the implementation of the proposed strategy.

In addition to the work on revising the Committees documents, the Hydromet Committee also provided the Operating Committee with a review of the Libby forecast procedure for the 2000 water year. The Operating Committee tasked the Hydromet Committee with looking into the variability of the Libby volume forecast as compared to the observed volume in 2000. In general, the following points were highlighted in the report:

The main causes for the variability between the forecasts and the observed volume at Libby were:

- Record high November runoff due to a heavy, warm rain event which occurred in late November. The November runoff is part of the Fall Runoff (FRO) term in the equation. The FRO term has a relatively small coefficient, however, the magnitude of the fall runoff which occurred in 1999, made this a contributor to the overall error.
- Generally mild winter temperatures made the distribution of snow in the Libby basin difficult to assess by the sites used in the procedure. Generally the snow course sites used in the Libby basin forecast procedure actually lie outside the basin. The representation as well as the uneven distribution caused the procedure to have difficulty actually assessing the snow pack conditions.
- The forecast procedure assumes normal subsequent precipitation. Spring precipitation in the Libby basin was below normal resulting in a slight decrease in overall runoff.

It was also noted that the 1 July 2000 forecast came from the River Forecast Center's forecast procedures, since the USACE forecast procedure can only provide forecasts up through June.

Permanent Engineering Board

Provisions for the establishment of the Permanent Engineering Board (PEB) and its duties and responsibilities are included in the Treaty and related documents. The members of the PEB are presently:

UNITED STATES SECTION	CANADIAN SECTION
Stephen L. Stockton, Chair San Francisco, California	Daniel R. Whelan, Chair Ottawa, Ontario
Ronald H. Wilkerson, Member Missoula, Montana	Jack Ebbels, Member Victoria, British Columbia
Earl E. Eiker, Alternate nominee Washington, D.C.	James Mattison, Alternate Victoria, British Columbia
George E. Bell, Alternate Portland, Oregon	David E. Burpee, Alternate′ Ottawa, Ontario
Robert A. Bank, Secretary Washington, D.C.	David E. Burpee, Secretary Ottawa, Ontario

Mr. Mattison was appointed to replace Mr. Prad Kharė in October 1999; Mr. Ebbels was appointed to replace Mr. Charles S. Kang on 14 September 2001.

Under the Treaty, the PEB is to assemble records of flows of the Columbia River and the Kootenay River at the international boundary. It is also to report to both governments if there is deviation from the hydroelectric or flood control operating plans, and if appropriate, include recommendations for remedial action. Additionally, the PEB is to:

- assist in reconciling differences that may arise between the Entities;
- make periodic inspections and obtain reports as needed from the Entities to assure that Treaty objectives are being met;
- prepare an annual report to both governments and special reports when appropriate;
- consult with the Entities in the establishment and operation of a Hydrometeorological system; and
- investigate and report on any other Treaty related matter at the request of either government.

The Entities continued their cooperation with the PEB during the past year by providing copies of Entity agreements, operating plans, downstream power benefit computations, Operating Committee agreements, updates to Hydrometeorological documents, and the annual Entity report to the Board for their review. The annual joint meeting of the PEB and the Entities was held on the morning of 21 February 2001 in Vancouver, B.C., where the Entities briefed the PEB on the preparation and implementation of operating plans, the delivery of the Canadian Entitlement, and other topics requested by the Board.

PEB Engineering Committee

The PEB has established a PEB Engineering Committee (PEBCOM) to assist in carrying out its duties. The members of PEBCOM at the end of the period of this report were:

UNITED STATES SECTION	CANADIAN SECTION
Robert A. Bank, Chair Washington, D.C.	Roger S. McLaughlin, Chair Victoria, British Columbia
Michael S. Cowan, Member Lakewood, CO	David E. Burpee, Member Ottawa, Ontario
Kamau B. Sadiki, Member Portland, OR	Donna Clarke, Member Ottawa, Ontario
D. James Fodrea, Member Boise, ID	Dr. G. Bala Balachandran, Member Victoria, British Columbia

Ms. Donna Clarke was appointed to replace Ms. Myriam Boudreault on 21 February 2001.

Mr. Kamau B. Sadiki was appointed on an interim basis to replace Mr. James Barton on 26 September 2001.

The PEBCOM met with the Operating Committee on 24 October 2000 in Portland Oregon.

International Joint Commission

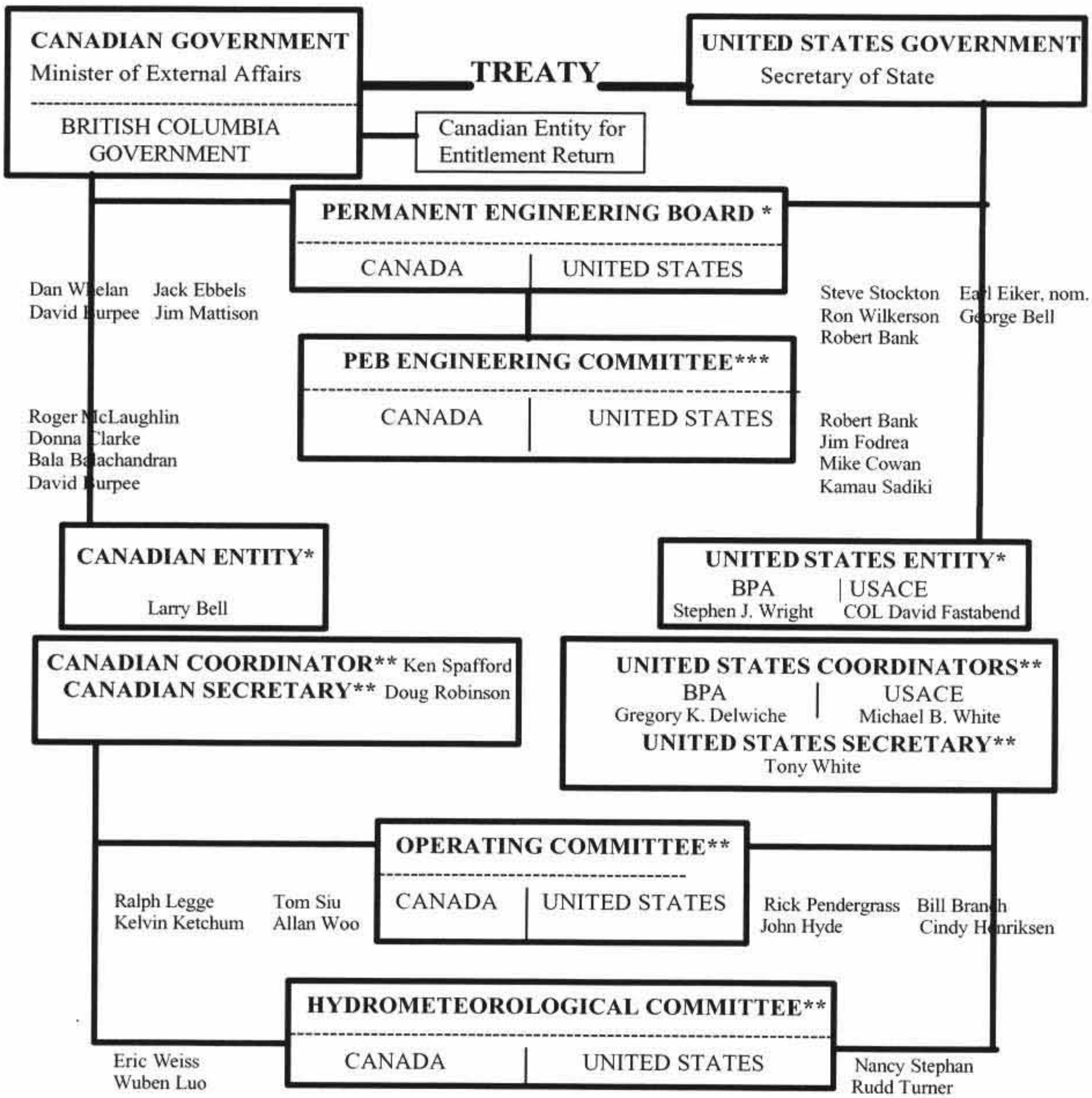
The International Joint Commission (IJC) was created under the Boundary Waters Treaty of 1909 between Canada and the U.S. Its principal functions are rendering decisions on the use of boundary waters, investigating important problems arising along the common frontier not necessarily connected with waterways, and making recommendations on any question referred to it by either government. If the Entities or the PEB cannot resolve a dispute concerning the Columbia River Treaty, that dispute may be referred to the IJC for resolution.

The IJC has appointed local Boards of Control to insure compliance with IJC orders and to keep the IJC informed. There are three such boards west of the continental divide. These are the

International Kootenay Lake Board of Control, the International Columbia River Board of Control, and the International Osoyoos Lake Board of Control. The Entities and the IJC Boards conducted their Treaty activities during the period of this report so that there was no known conflict with IJC orders or rules.

The United States Section Chair is Thomas L. Baldini of Marquette, MI. The Canadian Section Chair is Mary Gusella.

COLUMBIA RIVER TREATY ORGANIZATION



* ESTABLISHED BY TREATY
** ESTABLISHED BY ENTITY
*** ESTABLISHED BY PEB

Figure 4

III Operating Arrangements

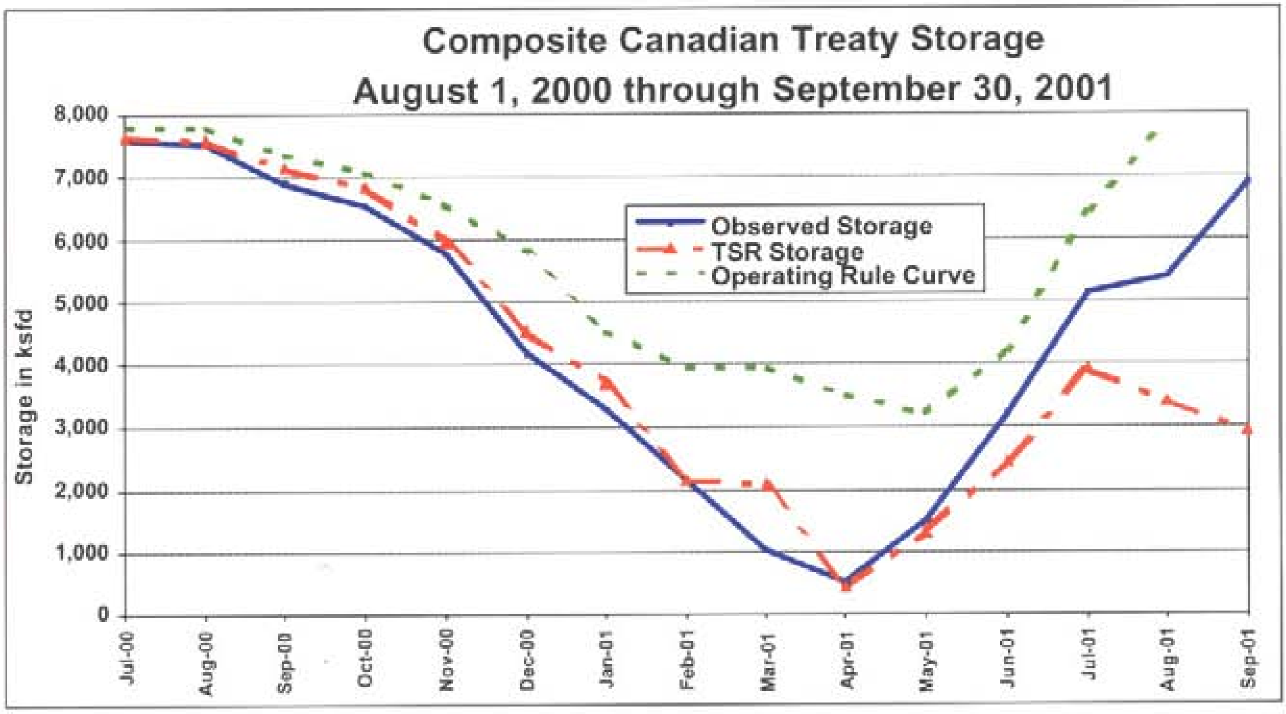
Power and Flood Control Operating Plans

The Columbia River Treaty requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed thereunder. Annex A of the Treaty stipulates that the United States Entity will submit flood control operating plans (FCOP). Annex A also says that the Canadian Entity will operate in accordance with flood control storage diagrams or any variation which the Entities agree will not reduce the desired aim of the flood control plan. Annex A also provides for the development of hydroelectric operating plans six years in advance to furnish the Entities with an AOP for Canadian Storage. Article XIV.2.k of the Treaty provides that a DOP be developed that may produce results more advantageous than the AOP. The Protocol to the Treaty provides further detail and clarification of the principles and requirements of the Treaty.

The "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans" dated December 1991 together with the "Columbia River Treaty Flood Control Operating Plan" dated October 1999, establish and explain the general criteria used to develop the AOP and DOP and operate Treaty storage during the period covered by this report.

The planning and operation of Treaty Storage as discussed on the following pages is for the operating year, 1 August 2000 through 31 July 2001. The operation of Canadian Storage was determined by the 2001 DOP and several supplemental operating agreements. The DOP required a bimonthly Treaty Storage Regulation (TSR) study to determine end-of-month storage obligations prior to any supplemental operating agreements. The TSR included all operating criteria from, and was based on, the Step I Joint Optimum Power hydroregulation study from the 2000-01 AOP, with agreed changes. The changes were minor and mainly updates to flood control rule curves, powerhouse definition data, and the operation of the Brownlee project. Most of the hydrographs and reservoir charts in this report are for a thirteen-month period, July 2000 through July 2001.

The following chart compares the observed operation of the composite Canadian Treaty Storage to the results of the DOP TSR study. The TSR was regulated to draft proportionally below the Operating Rule Curve (ORC) during 16 August 2000 through 30 September 2001.



Assured Operating Plans

The 2000-01 and 2001-02 AOP's, both dated January 2000, established ORC's, Mica Operating Criteria, and other operating criteria for Duncan, Arrow, and Mica that were used to guide the operation of Canadian storage during the period covered by this report. The ORC's provide guidelines for draft and refill under a wide range of normal water conditions. They were derived from Critical Rule Curves (CRC), Assured Refill Curves, Upper Rule Curves, Variable Refill Curves (VRC's), and Lower Limit Rule Curves, consistent with flood control requirements, as described in the 1991 Principles and Procedures document. The Flood Control Storage Reservation Curves were established to conform to the 1999 Flood Control Operating Plan, and are used to define an upper limit to the operation of Canadian storage. The CRC's are used to apportion draft below the ORC when the TSR determines additional draft is needed to meet the Coordinated System firm energy load carrying capability.

In August 2001, the Entities completed and agreed to the 2005-06 AOP/DDPB, and initiated studies for the 2006-07 AOP/DDPB. The Entities recognize that the AOP/DDPB studies are behind the desired schedule, and are continuing their efforts to insure completion six years prior to the operating year.

Determination of Downstream Power Benefits

For each operating year, the Determination of Downstream Power Benefits (DDPB) resulting from Canadian Treaty storage for the sixth succeeding year is made in conjunction with the AOP. The total downstream power benefits for operating year 2000-01 ~~were~~ was determined to be 1016.9 MW average annual usable energy and 2894.5 MW dependable capacity.

For operating years 2000-01 and 2001-02 the estimate of benefits resulting from operating plans designed to achieve optimum operation in both countries was not less than that which would have prevailed from an optimum operation in the United States only. Therefore, the Entities agreed that, in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement (CEPA) a contract between B.C. Hydro and the Columbia Storage Power Exchange (CSPE), the United States was not entitled to receive any energy or capacity.

In conjunction with the AOP studies, the Entities completed the 2005-06 DDPB that defines the Canadian Entitlement for the 2005-06 operating year, and initiated studies for the 2006-07 DDPB.

Return of Canadian Entitlement

The Canadian Entitlement to downstream power benefits was sold to a nonprofit organization, the CSPE (a consortium of 41 Northwest public and private utilities), in accordance with the CEPA for a period of thirty years following the Treaty-specified required completion date for each Canadian storage project. The purchase of Entitlement under CEPA expired 31 March 1998 for Duncan, 31 March 1999 for Arrow, and will expire 31 March 2003 for Mica.

On 1 April 1998 Entitlement power began returning to Canada at the U.S.-Canada border, over existing power lines, as established by the 20 November 1996 Entity Agreement on Aspects of the Delivery of the Canadian Entitlement. For the period 1 August 2000 through 31 July 2001, the amount returned for Duncan and Arrow was 277.4 aMW of energy, scheduled at rates up to 793.7 MW. The energy value includes a 2.5 aMW reduction in accordance with item 7 of the "Columbia River Treaty Entity Agreement on the 1998/99, 1999/00, and 2000/01 AOP and DDPB Studies," dated 5 April 1995. For the period 1 August 2001 through 31 September 2001, the amount returned for Duncan and Arrow was 292.1 aMW of energy, scheduled at rates up to 783 MW.

Detailed Operating Plan

During the period covered by this report, the Operating Committee used the 1 August 2000 through 31 July 2001 "Detailed Operating Plan for Columbia River Treaty Storage", dated July 2000 and the 1 August 2001 through 31 July 2002 DOP, dated July 2001, to guide storage operations. These DOP's established criteria for determining the Operating Rule Curves, proportional draft points, and other operating data for use in actual operations. The DOP used AOP loads and resources, and AOP rule curves for both Canadian and U.S. projects to develop the TSR study. The TSR study is updated twice monthly throughout the operating year, and together with any supplemental operating agreements, defines the end-of-month draft rights for Canadian storage. The VRC's and flood control requirements subsequent to 1 January 2001 were determined on the basis of seasonal volume runoff forecasts during actual operation. The Operating Committee directed the regulation of the Canadian storage, on a weekly basis throughout the year, in accordance with the applicable DOP's and supplemental operating agreements made thereunder.

Libby Coordination Agreement

During the period covered by this report, the Libby Coordination Agreement (LCA) procedures allowed the Canadian Entity to provisionally draft Arrow reservoir and exchange power with the U.S. Entity, and required delivery to the U.S. Entity one average MW, shaped flat, over the entire operating year. In accordance with the LCA, the Libby Operating Plan was updated by the U.S. Army Corps of Engineers after the USFWS delivered their 2000 Biological Opinion.

Entity Agreements

During the period covered by this report, two joint U.S.-Canadian arrangements were approved by the Entities. The following tabulation indicates the date each of these were signed and gives a description of the agreement:

Date Agreement Signed by Entities	Description
13 July 2001	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 2001through 31 July 2002.
16 August 2001	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2005-06.

Operating Committee Agreements

During the period covered by this report, the Operating Committee approved four joint U.S. - Canadian agreements. The following tabulation indicates the dates they were signed, gives descriptions of the agreements, and cites the authority for entering into the agreements:

Date Agreement Signed by Committee	Description	Authority
23 August 2000	Columbia River Treaty Operating Committee Agreement on Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning for The Period 1 September 2000 through 30 April 2001 (signed previous OY but effective during the current OY)	Detailed Operating Plan, 1 August 2000 through 31 July 2001, approved 11 July 2000 and dated July 2000
30 November 2000	Columbia River Treaty Operating Committee Agreement on Nonpower Uses for 1 January through 31 July 2001	Detailed Operating Plan, 1 August 2000 through 31 July 2001, approved 11 July 2000 and dated July 2000
29 December 2000	Agreement on Implementation of the Arrow Local Method for Canadian Treaty Storage for Operating Year 2000-01, among the Columbia River Treaty Operating Committee, the Bonneville Power Administration, and the British Columbia Hydro and Power Authority	Detailed Operating Plan, 1 August 2000 through 31 July 2001, approved 11 July 2000 and dated July 2000
8 May 2001	Agreement for Optimal Balancing of Storage Between Arrow and Libby Reservoirs for the period 13 February 2001 through 3 April 2001, among the Columbia River Operating Committee, the Bonneville Power Administration, and the British Columbia Hydro and Power Authority	Detailed Operating Plan, 1 August 2000 through 31 July 2001, approved 11 July 2000 and dated July 2000
18 July 2001	Columbia River Treaty Operating Committee Agreement on Operation of Summer Treaty Storage for 1 August 2001 through 31 March 2002	Detailed Operating Plan, 1 August 2000 through 31 July 2001, approved 11 July 2000 and dated July 2000

Long Term Non-Treaty Storage Contract

An Entity Agreement dated 9 July 1990 approved the contract between B.C. Hydro and BPA relating to the initial filling of non-Treaty storage, coordinated Use of non-Treaty storage, and Mica and Arrow refill enhancement. The Operating Committee, in accordance with that agreement, monitored the storage operations made under this Agreement throughout the operating year to insure that they did not adversely impact operation of Treaty storage.

IV Weather and Streamflow

Weather

In August of 2000 the basin experienced average to slightly above average temperature and below normal precipitation. In the Columbia basin precipitation averaged 36 percent of normal at Columbia above Grand Coulee; 38 percent of normal on the Snake River above Ice Harbor; and 35 percent of normal on the Columbia River above The Dalles.

September experienced above average precipitation at the three major measuring points on the Columbia and Snake Rivers. With the last in the series of fronts in September, record low temperatures occurred at Kalispell, Montana; Spokane, Washington; and Pocatello, Idaho (-5.6 °C, or 22 °F); -3.3 °C (26 °F) at Olympia, Washington; Salem, Oregon at 0 °C (32 °F); Astoria, Oregon at 2.2 °C (36 °F); Eugene, Oregon, and Lewiston, Idaho, at –0.6 °C (31 °F); and Pendleton, Oregon at 0.6 °C (33 °F). Precipitation averaged 116 percent of normal at the Columbia above Grand Coulee; 113 percent of normal at the Snake above Ice Harbor; and 122 percent of normal at the Columbia above The Dalles. Chart 3 shows the accumulated precipitation at Grand Coulee, Ice Harbor, and The Dalles during the 2001 water year.

October was the last month of 2000 with near average to above average precipitation. The Columbia River above Grand Coulee had 96 percent of average precipitation; the Snake River above Ice Harbor had 198 percent of average precipitation; and the Columbia River above The Dalles had 118 percent of average.

In November the precipitation in the region changed dramatically when only weak fronts moved into the basin. Precipitation was only 43 percent, 48 percent, and 49 percent of normal at Grand Coulee, Ice Harbor, and The Dalles, respectively. November also brought some record low temperature in the southern basins.

A pattern of split-flow continued in December 2000, and high pressure aloft dominated the Basin. Only a few weak storms broke through and offered little contributory precipitation. Precipitation averaged 63 percent of normal at Columbia above Grand Coulee; 55 percent of normal at the Snake River above Ice Harbor; and 57 percent of normal at Columbia above The Dalles. Temperatures averaged below normal for the month, which was punctuated with an artic cold snap

December 11 and 12. Chart 4 is the monthly average temperature departures across the Columbia Basin during December. This is indicative of the cold temperature during the month.

With little change in the upper air pattern from November and December, precipitation continued below normal in January 2001. Weak disturbances managed to either drift into B.C. or cut across the far southern U.S. districts en route toward the Desert Southwest. Regional temperatures were above normal due to the absence of the cool northerly flow aloft. Precipitation was 36 percent of normal at the Columbia River above Grand Coulee; 51 percent of normal on the Snake River above Ice Harbor; and 40 percent at the Columbia River above The Dalles.

In February temperatures were below normal as was precipitation. Precipitation averaged 55 percent of normal at the Columbia River above Grand Coulee and at the Snake River above Ice Harbor; 51 percent of normal at the Columbia River above The Dalles.

By March 2001 the pattern continued with a split flow, but some stronger storms managed to stay together through the northern branch of the split. Some frequent precipitation came into Canada and the northern U.S. Precipitation averaged 84 percent of normal at the Columbia River above Grand Coulee; 71 percent of normal at Snake River above Ice Harbor; and 82 percent of normal at the Columbia River above The Dalles.

Finally by April 2001 more storms were able to penetrate the basin as the split flow pattern consolidated.

The wet pattern of April continued into early May 2001 as a few storms managed to keep active along the northern branch of the split flow. Consequently, they brought precipitation to the northern basins. This storm track dissolved mid to late in the month. Regional temperatures averaged above normal, and temperature records were broken: 35 °C (95 °F) at Portland, Oregon, and Boise, Idaho, 37.8 °C (100 °F) at Medford, Oregon and 33.3 °C (92 °F) at Pocatello, Idaho. May precipitation averaged 59 percent of normal at the Columbia River above Grand Coulee; 48 percent of normal on the Snake River above Ice Harbor; and 62 percent of normal on the Columbia River above The Dalles.

Below normal temperatures and above normal precipitation covered most of the Basin in early June 2001. A westerly flow aloft brought the most frequent storms across the northern basins, while the southern basins remained dry. Precipitation for June was 117 percent of normal at the

Columbia River above Grand Coulee; 65 percent of normal at the Snake River above Ice Harbor; and 99 percent of normal at Columbia above The Dalles.

In July 2001, onshore flow governed by offshore upper level low pressure brought above normal precipitation to much of the Basin while keeping temperatures slightly below normal region-wide. Precipitation averages included 102 percent of normal at the Columbia River above Grand Coulee; 118 percent of normal at the Snake River above Ice Harbor; and 103 percent of normal at the Columbia River above The Dalles.

The offshore low pressure moved west and was replaced with upper level high pressure as the split flow aloft regained footing during August 2001. Although a sub-tropically fed storm brought above normal precipitation totals to part of B.C. and districts west of the Cascades, precipitation was mainly below normal even with this active weather system. For August, precipitation was 32 percent of normal at the Columbia River above Grand Coulee; 20 percent of normal at the Snake River above Ice Harbor; and 32 percent of normal at the Columbia River above The Dalles.

Streamflow

Monthly and Seasonal reservoir inflow at many key locations throughout the Columbia Basin are shown in Chart 5. The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 2000 through 31 July 2001 are shown on Charts 6 through 8. Chart 9 shows Libby hydrographs. Observed flow with the computed unregulated flow hydrographs for the same 13_month period for Kootenay Lake, Columbia River at Birchbank, Grand Coulee and The Dalles are shown on Charts 10, 11, 12 and 13, respectively. Chart 14 is a hydrograph of observed and two unregulated flows at The Dalles during the April through July 2001 period, including a plot of flows occurring if regulated only by the four Treaty reservoirs.

Composite operating year unregulated streamflows in the basin above The Dalles were below normal, and about 31 percent below last year's average streamflows. May was the high month during the spring runoff, being in the 68-percent-of-normal range. The August 2000 through July 2001 runoff for The Dalles was 101.9 km^3 (82.6 Maf), 78 percent of the 1961-90 average, and the lowest on record for the period 1928 through 2001. The peak regulated discharge for the Columbia River at The Dalles was 9,253.9 m3/s (326,800 cfs) on 30 May 2001. The 2000-01 monthly unregulated (natural) streamflows and their percentage of the 1961-90 average monthly flows are shown in the following two tables (metric and English) for the Columbia River at Grand Coulee and The Dalles. These flows have been corrected to exclude the effects of regulation provided by storage reservoirs.

Columbia River Flow in Metric Units

	Columbia River at Grand Coulee in m^3/s		**Columbia River at The Dalles in m^3/s**	
Time Period	Natural Flow	Percentage of Average	Natural Flow	Percentage of Average
Aug 00	2597.8	88	3261.4	84
Sep 00	1657.0	91	2496.0	92
Oct 00	1199.2	88	2230.3	92
Nov 00	857.0	62	1769.3	68
Dec 00	699.1	58	1622.0	61
Jan 01	723.5	62	1520.6	55
Feb 01	611.3	46	1522.5	46
Mar 01	822.5	49	2157.1	54
Apr 01	1506.6	46	3147.4	50
May 01	5378.4	72	8141.1	68
Jun 01	4935.3	53	6517.6	46
Jul 01	3506.9	65	4249.3	58
Operating Period	2050.8	64	3230.6	78

Columbia River Flow in English Units

Time Period	Columbia River at Grand Coulee in cfs: Natural Flow	Percentage of Average	Columbia River at The Dalles in cfs: Natural Flow	Percentage of Average
Aug 00	91,741	88	115,160	84
Sep 00	58,516	91	88,144	92
Oct 00	42,349	88	78,763	92
Nov 00	30,266	62	62,482	68
Dec 00	24,688	58	57,279	61
Jan 01	25,549	62	53,701	55
Feb 01	21,589	46	53,765	46
Mar 01	29,046	49	76,177	54
Apr 01	53,206	46	111,150	50
May 01	189,938	72	287,501	68
Jun 01	174,288	53	230,166	46
Jul 01	123,844	65	150,061	58
Operating Period	72,424	64	114,086	78

Seasonal Runoff Forecasts and Volumes

Observed 2001 April through August runoff volumes, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin:

Location	Volume in km^3	Volume in 1000 Acre-Feet	Percentage of 1961-90 Average
Libby Reservoir Inflow	3.92	3,174	50
Duncan Reservoir Inflow	1.92	1,555	76
Mica Reservoir Inflow	10.84	8,786	76
Arrow Reservoir Inflow	21.83	17,699	76
Columbia River at Birchbank	31.30	25,375	62
Grand Coulee Reservoir Inflow	46.16	37,422	61
Snake River at Lower Granite	13.65	11,065	48
Columbia River at The Dalles	65.12	52,790	57

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2001 for a large number of locations in the Columbia River Basin and updated each month as the season advanced. Table 1 lists the April through August inflow volume forecasts for Mica, Arrow, Duncan and Libby projects and for unregulated runoff for the Columbia River at The Dalles. Also shown in Table 1 and Table 1M (pages 48 and 49) are the actual volumes for these five locations. The forecasts for Mica, Arrow, and Duncan inflow were prepared by B.C. Hydro. The forecasts for the lower Columbia River and Libby inflows were prepared by the National Weather Service and River Forecast Center, in cooperation with the USACE, National Resource Conservation Service, Bureau of Reclamation, and B.C. Hydro. The 1 April 2001 forecast of January-through-July runoff for the Columbia River above The Dalles was 69.20 km^3 (56.1 Maf) and the actual observed runoff was 71.54 km^3 (58.0 Maf).

The following tabulation summarizes monthly forecasts since 1970 of the January-through-July runoff for the Columbia River above The Dalles compared with the actual runoff measured in km^3 (Maf). The average January-July runoff for the 1961-90 period was 130.63 km^3 (105.9 Maf).

The Dalles Volume Runoff Forecasts in km^3 (Jan-Jul)

Year	Jan	Feb	Mar	Apr	May	Jun	Actual
1970	101.8	122.7	115.2	116.3	117.3		118
1971	136.8	159.7	155.4	165.3	164.1	166.5	169.6
1972	135.8	157.9	171.1	180.2	180.1	180.1	187.1
1973	114.8	111.6	104.5	102.4	99.2	97.1	87.8
1974	151.7	172.7	180.1	183.8	181.3	181.3	192.8
1975	118.5	131.0	141.5	143.9	142.1	139.4	138.6
1976	139.4	143.1	149.3	153.0	153.0	153.0	151.5
1977	93.4	76.7	69.0	71.7	66.4	70.8	66.4
1978	148.0	140.6	133.2	124.6	128.3	129.5	130.3
1979	108.5	97.0	114.7	107.7	110.6	110.6	102.5
1980	109.7	109.7	109.7	110.6	111.8	120.5	118.2
1981	130.7	104.5	104.2	101.1	102.6	118.3	127.5
1982	135.7	148.0	155.4	160.4	161.6	157.9	160.2
1983	135.7	133.2	139.4	149.3	149.3	146.8	146.4
1984	139.4	127.0	120.4	125.8	132.0	140.6	146.9
1985	161.6	134.5	129.5	121.6	121.6	123.3	108.2
1986	119.4	115.1	127.0	130.7	133.2	133.2	133.6
1987	109.7	101.0	96.2	98.7	94.6	93.5	94.4
1988	97.7	92.3	89.7	91.3	93.9	92.5	90.9
1989	124.6	125.8	116.2	122.7	121.6	119.5	111.8
1990	106.7	124.6	128.3	118.4	118.4	122.7	123
1991	143.1	135.7	132.0	130.7	130.7	128.3	132.1
1992	114.2	109.9	103.0	87.8	87.8	83.6	86.8
1993	114.2	106.1	95.3	94.5	101.0	106.2	108.5
1994	98.3	94.1	96.3	90.3	93.1	94.2	92.5
1995	124.6	122.9	116.3	122.9	122.9	120.8	128.3
1996	143.1	150.5	160.4	155.4	165.3	173.9	171.8
1997	170.2	178.9	175.2	183.8	188.7	196.1	196.1
1998	106.6	117.4	113.1	112.0	109.9	124.6	128.3
1999	143.1	146.8	160.4	157.9	153.0	151.7	153.1
2000	129.5	130.7	129.5	129.5	129.5	125.8	120.9
2001	99.2	81.9	72.3	69.2	69.7	68.5	71.8

The Dalles Volume Runoff Forecasts in Maf (Jan-Jul)

Year	Jan	Feb	Mar	Apr	May	Jun	Actual
1970	82.5	99.5	93.4	94.3	95.1		95.7
1971	110.9	129.5	126.0	134.0	133.0	135.0	137.5
1972	110.1	128.0	138.7	146.1	146.0	146.0	151.7
1973	93.1	90.5	84.7	83.0	80.4	78.7	71.2
1974	123.0	140.0	146.0	149.0	147.0	147.0	156.3
1975	96.1	106.2	114.7	116.7	115.2	113.0	112.4
1976	113.0	116.0	121.0	124.0	124.0	124.0	122.8
1977	75.7	62.2	55.9	58.1	53.8	57.4	53.8
1978	120.0	114.0	108.0	101.0	104.0	105.0	105.6
1979	88.0	78.6	93.0	87.3	89.7	89.7	83.1
1980	88.9	88.9	88.9	89.7	90.6	97.7	95.8
1981	106.0	84.5	84.5	81.9	83.2	95.9	103.4
1982	110.0	120.0	126.0	130.0	131.0	128.0	129.9
1983	110.0	108.0	113.0	121.0	121.0	119.0	118.7
1984	113.0	103.0	97.6	102.0	107.0	114.0	119.1
1985	131.0	109.0	105.0	98.6	98.6	100.0	87.7
1986	96.8	93.3	103.0	106.0	108.0	108.0	108.3
1987	88.9	81.9	78.0	80.0	76.7	75.8	76.5
1988	79.2	74.8	72.7	74.0	76.1	75.0	73.7
1989	101.0	102.0	94.2	99.5	98.6	96.9	90.6
1990	86.5	101.0	104.0	96.0	96.0	99.5	99.7
1991	116.0	110.0	107.0	106.0	106.0	104.0	107.1
1992	92.6	89.1	83.5	71.2	71.2	67.8	70.4
1993	92.6	86.5	77.3	76.6	71.9	86.1	88.0
1994	79.7	76.3	78.1	73.2	75.5	76.4	75.0
1995	101.1	99.6	94.3	99.6	99.6	97.9	104.0
1996	116.0	122.0	130.0	126.0	134.0	141.0	139.3
1997	138.0	145.0	142.0	149.0	153.0	159.0	159.0
1998	86.4	95.2	91.7	90.8	89.1	101.0	104.0
1999	116.0	1193.0	130.0	128.0	124.0	123.0	124.1
2000	105.0	106.0	105.0	105.0	105.0	102.0	98.0

V Reservoir Operation

General

The 2000-2001 operating year began with normal to slightly above normal precipitation; however by November the basin became dry and snowpack was not building. Although the first official water supply forecast prepared in January 2001 by the National Weather Service River Forecast Center was 76 percent of average (99.17 km^3 (80.4 Maf) for the January through July period) for the period 1961-1990, each successive months' final water supply forecast diminished. By April 2001, the water supply forecast was at 53 percent of average (69.20 km^3 (56.1 Maf) for the January through July period).

By the end of April many reservoirs in the U.S. had been drafted very deeply to meet U.S. power needs through the winter. The flow was also being used to maintain a minimum flow at Bonneville Dam from November through April for listed chum downstream of Bonneville Dam. Canadian reservoirs also had drafted deeply to meet power needs.

The winter of 2000-2001 was very dry and was characterized by low natural stream flow. By early December the U.S. was using water in storage to maintain a flow of 3964.35 m^3/s (140 kcfs) at Bonneville Dam to keep the chum spawning area downstream of Bonneville Dam wet. Once the chum are in the area and have spawned this flow should be maintained through early May when the fish emerge.

By mid-December the Pacific Northwest experienced a short duration cold snap, where water was used in Federal reservoirs to meet the regional power demands. Both the NMFS and the USFWS issued final Biological Opinions on 21 December 2000. These Biological Opinions covered all the fish species and encompass all the previous supplements to the 1995 Biological Opinions.

In January as streamflow remained low, BPA experienced a longer duration power emergency where Federal reservoirs were used again to draft water from storage to meet regional power needs. By 4 April 2001, BPA declared another power emergency. This emergency caused the USACE to be unable to spill up to the full amounts recommended in the NMFS 2000 Biological Opinion.

The final observed runoff at The Dalles for the period January thorough July 2001 was 71.79 km^3 (58.2 Maf), 55 percent of average. This is the second lowest for the period since 1928.

Because this was slightly greater than the April through June water supply forecasts, the USACE was able to spill some water in August to help listed juvenile fish migration.

The 2000 Biological Opinions have much the same operational provisions as the other Opinions and Supplements. These provisions include seasonal flow objectives at certain dams, which are based on a sliding scale water supply forecast:

- Lower Granite, 2406.93-2831.68 m^3/s (85,000-100,000 cfs) during 10 April - 20 June, and 1415.84-1557.43 m^3/s (50,000-55,000 cfs) during 21 June-31 August.
- McNary, 6229.70-7362.37 m^3/s (220,000-260,000 cfs) during 20 April – 30 June, and 5663.36 m^3/s (200,000 cfs) during 1 July 31 August.
- Priest Rapids, 3822.77 m^3/s (135,000 cfs) during 3 April through 20 June. (This objective does not vary with water supply).

The NMFS Biological Opinion also recommends that Federal projects be as full as their 10 April flood control point, and full on 31 June. Then the projects may draft in July and August for summer flow augmentation.

Because of the extreme low water conditions in the spring of 2001 and the use of water earlier in the season for power and chum operations, the Federal projects were well below 10 April flood control points. None of the Federal projects were able to fill on 30 June, but all projects evacuated to their draft limits in 2001.

The USFWS Biological Opinion recommends operations for Libby Dam to meet listed sturgeon needs in the Kootenai River. The USFWS Biological Opinion also recommends that in water years where the water supply forecast is in the statistical lower one-fifth of the water years, there be no sturgeon pulse operation in spring. Since this water year was statistically in the lowest one-fifth expected volume, there was no request for a sturgeon pulse operation from Libby in 2001.

Canadian Treaty Storage Operation

As specified in the DOP, the release of Canadian Treaty storage is made effective at the Canadian-United States border. Accordingly, releases from individual Canadian projects can vary from the release required by the DOP (TSR plus supplemental operating agreements) so long as this variance does not impact the ability of the Canadian system to deliver the sum of Treaty outflows from Arrow and Duncan reservoirs. Variances from the DOP storage operation are accumulated in respective Flex accounts. An overrun in an account occurs when actual project releases are greater (contents are lower) than those specified by the DOP. Conversely, an underrun occurs when actual project releases are less (contents are higher) than those specified by the DOP. Flex accounts for Mica, Revelstoke, Arrow, and Duncan are balanced at any point in time to ensure that under/overruns do not impact the total Treaty release required at the Canadian-United States border. The terms under/overrun are used in the description of Mica Reservoir operations below.

Mica Reservoir

As shown in Chart 6, the Mica Reservoir (Kinbasket Lake) level was at elevation 747.16 m (2451.3 feet) on 31 July 2000. The reservoir reached the maximum elevation for the year of 749.17 m (2457.9 feet) on 14 August 2000, 5.21 m (17.1 feet) below full pool elevation of 754.38 m (2475 feet).

Inflow into Mica reservoir was 91 percent of normal over the period August 2000 to December 2000. Over this same period, Mica outflow varied from a monthly average high of 925.96 m^3/s (32,700 cfs) in November to a monthly average low of 739.07 m^3/s (26,100 cfs) in December. From its peak elevation, the reservoir drafted rapidly due to below normal inflow and high load demand. By 31 December the reservoir reached 733.23 m (2405.6 feet), about 8.53 m (28 feet) below the average elevation for that date. The Mica Treaty storage account was at 8149.62 hm^3 (3331.0 ksfd (thousand second-foot-days) (6.6 Maf)) on 31 July 2000, reaching full storage of 8634.54 hm^3 (cubic hectometers) (3529.2 ksfd (7.0 Maf)) on 15 August 2000. By 31 December, Mica Treaty storage was drafted to 5322.82 hm^3 (2175.6 ksfd (4.3 Maf)). The average discharges through this period were similar to the sum of DOP and NTSA releases. The Mica project had an underrun of 53.83 hm^3 (22 ksfd) on 31 July 2000 and an overrun of 14.68 hm^3 (6 ksfd) on 31 December 2000. The B.C. Hydro NTSA was at 1719.47 hm^3 (702.8 ksfd) on 31 July 2000 and 578.13 hm^3 (236.3 ksfd) on 31 December 2000. The corresponding U.S. NTSA was at 1970.74 hm^3 (805.5 ksfd) and 878.33 hm^3 (359.0 ksfd), respectively.

Inflow into Mica reservoir was 78 percent of normal over the period January 2001 to August 2001. Outflow over this same period varied from a monthly average high of 770.22 m^3/s (27,200 cfs) in February to a monthly average low of 33.98 m^3/s (1,200 cfs) in June. The reservoir drafted to the minimum elevation for the year of 714.76 m (2345.0 feet) on 26 April 2001, only

1.37 m (4.5 feet) higher than the historical low pool elevation of 713.35 m (2340.4 feet) on 23 April 1993. Due to below normal spring temperatures, the freshet was delayed by about one month and inflow did not start appreciably until late May. The reservoir reached the maximum elevation for the year of 742.13 m (2434.8 feet) on 3 September 2001, 12.25 m (40.2 feet) below the full pool elevation of 754.38 m (2475 feet).

Mica Treaty storage reached minimum on 11 May 2001, with an overdraft of 30.34 hm^3 (12.4 ksfd) below empty. The overdraft was the result of the DOP Mica minimum flow criteria. Treaty storage gradually refilled with increasing inflow and reached the maximum of 5741.44 hm^3 (2346.7 ksfd (4.7 Maf)) on 24 August 2001. The Mica actual discharges were significantly less than the sum of Mica DOP and Non Treaty Storage Agreement (NTSA) releases from March 2001 through August 2001 due to the flex operation between Mica and Arrow. This resulted in a record underrun of 2791.57 hm^3 (1141 ksfd) by 20 September 2001. The previous historical maximum underrun was 2312.04 hm^3 (945 ksfd) on 6 July 1993. The B.C. Hydro and U.S. NTSA on 31 August 2000 was at 687.01 hm^3 (280.8 ksfd) and 725.42 hm^3 (296.5 ksfd), respectively.

Revelstoke Reservoir

During the 2000-01 operating year, the Revelstoke project was operated as a run-of-river plant with the reservoir level maintained generally within 0.91 m (3.0 feet) of its normal full pool elevation of 573.02 m (1880 feet). During the spring freshet, March through July, the reservoir operated as low as elevation 571.80 m (1876.0 feet), or 1.22 m (4 feet) below full pool, to provide additional operational space to control high local inflows. Changes in Revelstoke storage levels did not affect Treaty storage operations.

Arrow Reservoir

As shown in Chart 7, the Arrow Reservoir reached its maximum elevation for the year of 440.10 m (1443.9 feet) on 26 July 2000 with the Arrow Treaty storage reaching (3549 ksfd (7.0 Maf)) on 31 July 2000. The reservoir drafted through August and September and reached elevation 435.86 m (1430.0 feet) by the end of September.

Arrow discharge decreased over the autumn months from an average of 1648.04 m^3/s (58,200 cfs) in September to 923.13 m^3/s (32,600 cfs) in October and 1070.38 m^3/s (37,800 cfs) in

November. The discharge increased to an average of 1659.37 m^3/s (58,600 cfs) in December. The Arrow Reservoir drafted to elevation 4232.27 m (1418.2 feet) by 31 December 2000.

The Arrow fisheries operations were conducted under the terms of two Operating Committee agreements, "Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning for the period of 1 September 2000 through 30 April 2001" and "Operation of Treaty Storage for Nonpower Uses for 1 January through 31 July 2001". These agreements enabled the Arrow project flows to be adjusted to enhance whitefish and rainbow spawning and emergence downstream of the Arrow project in BC.

During the period 24 December 2000 to 22 January 2001, Arrow outflow was held near 1076.04 m^3/s (38,000 cfs) to maintain river levels during the whitefish spawning period that could be sustained through the period of emergence in February and March. Unlike the previous operating year where the Arrow TSR flow for January was higher than the preferred whitefish flows, the Arrow TSR flow for January 2001 was closer to the preferred January 2001 whitefish flow. As a result, B.C. Hydro did not need to exercise an available option to store up to 978.64 hm^3 (400 ksfd) under the agreement to enhance Mountain Whitefish. Arrow outflow through the period of whitefish emergence from 23 January to 23 March averaged 1387.52 m^3/s (49,000 cfs) which was higher than the whitefish spawning flows. On 24 March, the outflow from Arrow was reduced from 1274.26-849.50 m^3/s (45,000 cfs to 30,000 cfs) to meet objectives for rainbow trout spawning under the Non-Power Uses Agreement. Between 10 April and 29 May, Arrow outflow increased to 991.09 m^3/s (35,000 cfs), under the same agreement, to permit the U.S. Entity to meet the Vernita Bar salmon flow requirements.

In this operating year, the Columbia River Treaty Operating Committee agreed to use an alternative method for determining the Arrow VRC's between January and February 2001. The alternative method, known as the Arrow Local Method uses Mica outflow when computing Arrow's VRC, and on average, results in lower VRC's at Arrow during January through April than the normal method. The Arrow reservoir is still targeted to be full on 31 July. The agreement to use the alternate Arrow Local Method was signed in December 2000, with the expectation that power benefits realized in excess of those expected by the Total Method would be shared equally between BPA and B.C. Hydro. The Operating Committee agreed that operations under the 2001 Arrow Local Agreement resulted in a net generation gain in the U.S. system valued at of 6.48($U.S.) million. The B.C. Hydro share of this generation gain will be delivered to B.C. Hydro over the period October to December 2001 in accordance with the agreement.

During the year 2000-01, the U.S. did not store water in Arrow under the Non-Power Uses Agreement for the purpose of salmon flow augmentation. Inflow to Arrow was below average during the January through March storage period, and outflow needed to be maintained for whitefish spawning and power uses in the U.S. However, due to the low water supply, the Operating Committee did agree to a Summer Treaty Storage Agreement (STS) with mutually agreeable storage opportunities, for the enhancement of summer reservoir levels at Canadian Treaty projects and for the storage of additional water for U.S. Pacific Northwest reliability requirements during the fall and winter of 2001-02. In anticipation of this agreement, which was signed on July 2001, water was stored in Canadian Treaty reservoirs during June and July under the Non-Power Uses Agreement and later transferred to the STS agreement.

The Arrow reservoir drafted to a minimum elevation for the 2000-01 year of 422.18 m (1385.1 feet) on 22 May 2001 and only reached a maximum elevation of 430.41 m (1412.1 feet) on 3 August 2001, 9.72 m (31.9 feet) below the full pool elevation of 440.13 m (1444 feet). The highest Arrow Treaty storage content was 6507.47 hm^3 (2659.8 ksfd (5.3 Maf)) on 19 August 2001. The Coordinated Columbia System was on proportional draft throughout the operating year and Arrow Treaty storage was drafted to 6118.21 hm^3 (2500.7 ksfd (5.0 Maf)) at the end of August 2001.

The Arrow Lakes Power Company project at Keenleyside Dam began full construction of a powerhouse on 15 March 1999. The powerhouse will contain two generating units, each expected to be 85 MW capacity. Construction of the powerhouse may be completed as early as November 2001.

Figure 5: Above photographs of the progress being made on construction inside the powerhouse at Keenlyside Dam. The generating units may be commissioned in the fall of 2001, or the summer of 2002.

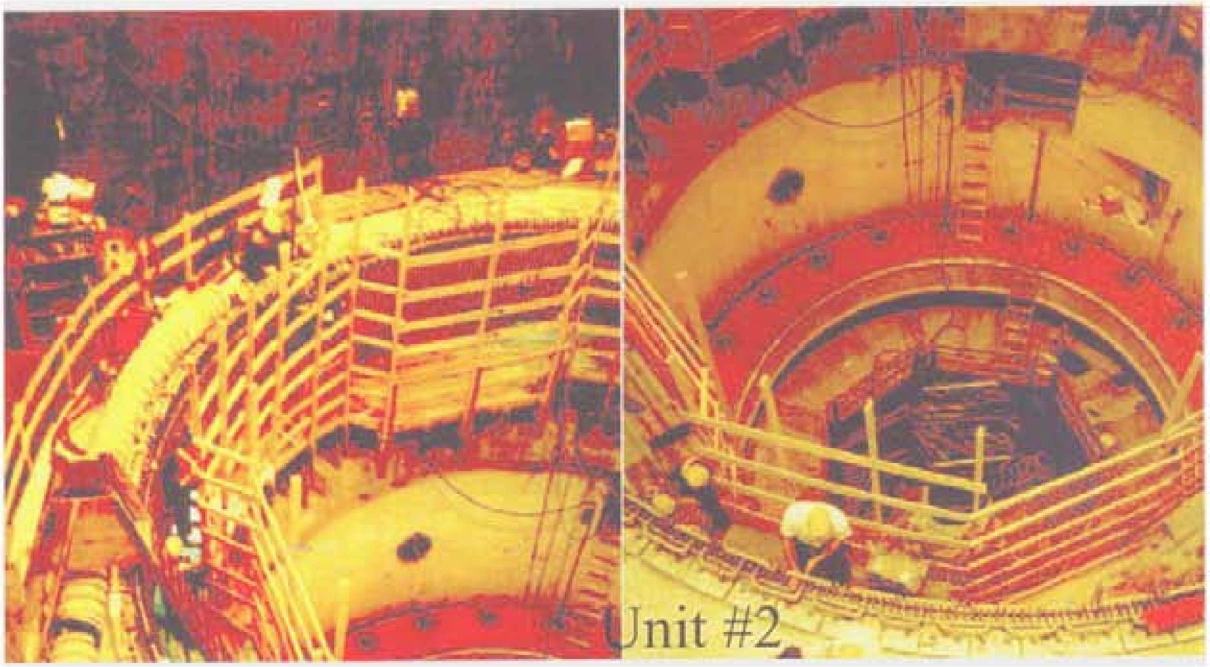


Figure 6: Progress on construction of Unit 2 in Keenleyside powerhouse.

Figure 7: Upstream approach channel to the new powerhouse at Keenleyside Dam, July 2001.

Duncan Reservoir

As shown in Chart 8, the Duncan reservoir was at the full pool elevation of 576.68 m (1892.0 feet) on 31 July 2000. For the period September through December, Duncan discharge averaged 203.88 m^3/s (7,200 cfs) as the reservoir was drafted to support Kootenay Lake elevations. On 31 December, the reservoir reached elevation 547.30 m (1795.6 feet), 0.43 m (1.4 feet) above empty. For the period January through April 2001, the Duncan project passed inflow, keeping the reservoir near empty.

Inflow to Duncan was 74 percent of normal for the period January 2001 to July 2001. Average outflow for this period was 16.99 m^3/s (600 cfs). The reservoir reached the maximum elevation for the 2000-01 year of 571.71 m (1875.7 feet) on 30 July 2001, 4.97 m (16.3 feet) below full pool elevation of 576.68 m (1892 feet).

During August, Duncan discharge was increased to an average of 175.56 m^3/s (6,200 cfs) to maintain Kootenay Lake elevations close to the maximum summer level permitted under the IJC Order. In doing so, the Duncan reservoir drafted to elevation 570.19 m (1870.7 feet) by month end. During September, the Duncan discharge was further increased to 283.17 m^3/s (10,000 cfs) to enable Kootenay Lake elevation to be raised up to the IJC limit of 531.97 m (1745.32 feet) for the period 1 September to 7 January.

Libby Reservoir

As shown in Chart 9, Lake Koocanusa began July 2000 at elevation 737.04 m (2418.1 feet), 12.47 m (40.9 feet) below full. After the spring 2000 sturgeon pulse, flow was ramped down from full load in June to 226.53 m^3/s (8,000 cfs) by 3 July. Originally USFWS requested a bull trout flow of 254.85 m^3/s (9,000 cfs), but modified their request to 226.53 m^3/s (8,000 cfs) to assist with refill of the project. By 31 July 2000, Lake Koocanusa was at elevation 742.04 m (2434.5 feet), 7.47 m (24.5 feet) from full. The possibility of a Libby/Arrow storage exchange agreement was considered, but did not appear to be beneficial to both parties. No exchange agreement was made. Libby did not fill above 743.41 m (2439 feet) in July 2000, which is the 1995 Biological Opinion interim draft limit for 31 August. As a result, the minimum bull trout flow of 226.53 m^3/s (8,000 cfs) was maintained in August and no additional outflow was required for compliance with the BiOp. The resulting end of month elevation in August was 742.16 m (2434.9 feet), 7.35 m (24.1 feet) from full and 1.25 m (4.1 feet) below the interim draft limit.

Inflow into Libby began dropping below normal in the fall. Inflow was 85 percent of normal for August, 70 percent of normal for October and 64 percent of normal for November. For the majority of September 2000, outflow was held steady at 226.53 m^3/s (8,000 cfs) and then was reduced to 169.90 m^3/s (6,000 cfs) by 24 September. Flow was maintained at 169.90 m^3/s (6,000 cfs) until 7 November when flow was increased to 339.80 m^3/s (12,000 cfs) for power generation needs. Outflow averaged 257.68 m^3/s (9,100 cfs) for the month of November and Lake Koocanusa ended the month at elevation 737.89 m (2420.9 feet).

In December 2000, there was a regionally declared power emergency. With an arctic front headed into the Northwest, the Northwest Security Coordinator issued a Regional Emergency Warning of Potential Alert 2 on 8 December. The warning was issued at the recommendation of the Regional Emergency Response team, which includes Northwest utilities, federal hydro operation agencies and states. A level 2 warning is tied to an emergency alert status (NERC Alert 2) prescribed by the North American Electric Reliability Council. It is called when regional forecast indicates firm load (contractual requirements to supply electricity) can only be met after including extraordinary actions in the projects. In response to this warning, Libby flow was increased to full load for a short time on 11 and 12 December. The Emergency warning was lifted on 12 December and the project gradually decreased flow back to 169.90 m^3/s (6,000 cfs). The project reached an end of December elevation of 735.03 m (2411.5 feet). December inflow averaged 73 percent of normal.

The January Final water supply forecast for 2001 was 5.88 km^3 (4.764 Maf), 74 percent of normal for the period of April through August. Outflow in January was maintained at 113.27 m^3/s (4,000 cfs) until 21 January to keep the project from drafting too far below the end of January flood control requirement and to aid Idaho Department of Fish and Game's burbot study. Outflow was ramped up to 283.17 m^3/s (10,000 cfs) on 22 January in response to generation needs for a power emergency. Libby inflow in January averaged 70.79 m^3/s (2,500 cfs), 76 percent of normal and the project ended the month at 733.29 m (2405.8 feet), 2.90 m (9.5 feet) below the 31 January flood control requirement of 614.26 m (2015.3 feet).

Outflow was maintained at 283.17 m^3/s (10,000 cfs) until 7 February at which time outflow ramped up to 424.75 m^3/s (15,000 cfs) to provide additional generation for the power emergency. Additional increases were planned for 13 February, but the Canadian Entity made a request in accordance with the Libby Coordination Agreement to limit outflow from Libby. A storage exchange agreement was drawn up and signed by the U.S. and Canada. Flow remained at 424.75 m^3/s (15,000 cfs) through the designated storage period of 13 - 19 February. In exchange for the reduced outflow from Libby, Canada provided additional discharge from Arrow and megawatts to the U.S. Flow was reduced to 169.90 m^3/s (6,000 cfs) by 23 February and remained there until 4 March. Libby reached an elevation of 728.84 m (2391.2 feet) on 28 February, 13.44 m (44.1 feet) below the required flood control elevation. February inflow averaged 73.62 m^3/s (2,600 cfs), 77 percent of normal. The February final water supply forecast for the period of April through August dropped to 4.86 km^3 (3.936 Maf), 61.7 percent of normal.

The March release averaged 124.59 m^3/s (4,400 cfs). Minimum flow of 113.27 m^3/s (4,000 cfs) was released from 7 - 6 March when flow was increased to 127.43 m^3/s (4,500 cfs) from 27 March - 3 April to return the remaining water owed to Canada per the February storage exchange agreement. Lake Koocanusa ended March at elevation 727.74 m (2387.6 feet), 17.41 m (60.4 feet) below the flood control elevation. March inflow was 76.46 m^3/s (2,700 cfs), which was 74 percent of normal.

Due to the extreme low water forecast, Libby remained at minimum discharge from 4 April - 1 July in an attempt to save water for multipurpose needs later. The project did not perform a sturgeon pulse operation in 2001. Libby inflow averaged 107.60 m^3/s (3,800 cfs) (47 percent of normal) in April; 467.23 m^3/s (16,500 cfs) (61 percent of normal) in May; and 489.88 m^3/s (17,300 cfs) (43 percent of normal) in June. Libby reached end of month elevations of 727.56 m (2387.0 feet) in April, 734.75 m (2410.6 feet) in May, and 741.00 m (2431.1 feet) in June. Water supply forecasts for the April - August period dropped again in April and rebounded slightly in May. The April final forecast was 4.10 km^3 (3.322 Maf) (52 percent of normal) and the May final forecast was up slightly to 4.33 km^3 (3.512 Maf) (55 percent of normal).

In July outflow was increased to 169.90 m^3/s (6,000 cfs) for bull trout needs. In July the USACE was alerted to an algae problem below Libby Dam. Montana Fish Wildlife and Parks wanted to conduct a pulsing operation at Libby to dislodge the algae from the rocks. During the coordination of the pulse operation, the USACE also received a request to increase outflows to aid in the retrieval of a drowning victim. To meet both requests, flow at Libby was increased to 283.17 m^3/s (10,000 cfs) for 24 hours and then ramped back down to 169.90 m^3/s (6,000 cfs). Both goals of the operation were met and the operation was a success. Libby reached an elevation of 742.88 m (2436.6 feet) on 31 July, 6.83 m (22.4 feet) from full. July inflow averaged 280.34 m^3/s (9,900 cfs), 48 percent of normal.

Outflow in August was held at 169.90 m^3/s (6,000 cfs) for bull trout. Inflow in August averaged 138.75 m^3/s (4,900 cfs), 50 percent of normal. The 31 August elevation for Lake Koocanusa was 742.16 m (2434.9 feet), 1.25 m (4.1 feet) below the BiOp interim draft limit of 743.41 m (2439.0 feet). Outflows in September were held at 169.90 m^3/s (6,000 cfs) for the whole month. Libby had a lake elevation of 740.97 m (2431.02 feet) on 30 September.

Kootenay Lake

As shown in Chart 10, the level of Kootenay Lake at Queens Bay was at elevation 531.73 m (1744.52 feet) on 31 July 2000. Kootenay Lake was drafted to ele vation 531.24 m (1742.9 feet) on 19 August and then filled gradually to near 531.34 m (1743.2 feet) by month end as the result of increased Duncan discharge. Kootenay Lake discharge averaged 673.94 m^3/s (23,800 cfs) in August.

Through the period September through December 2000, Kootenay Lake levels were maintained from between 0.09-.085 m (0.3 feet to 2.8 feet) of the IJC limit of 531.97 m (1745.32 feet). The month end levels for Kootenay over those four months were 531.88 m, 531.77 m, 531.48 m, and 531.13 m (1745.02 feet, 1744.66 feet, 1743.70 feet, and 1742.56 feet). The corresponding Kootenay Lake monthly average discharges for the four months were 529.52 m^3/s (18,700 cfs), 521.03 m^3/s (18,400 cfs), 580.49 m^3/s (20,500 cfs), and 535.19 m^3/s (18,900 cfs), respectively.

For the month of January, Kootenay Lake drafted to a low elevation of 530.63 m (1740.9 feet) in response to low natural inflow and reduced regulated outflow from Duncan. The levels, however, rose to elevation 530.72 m (1741.2 feet) by month end due to increase in Libby discharge beginning 23 January. Kootenay Lake discharge averaged 319.98 m^3/s (11,300 cfs) for the month.

From 10 February to 22 February 2001, the Kootenay Canal was dewatered to perform remediation work on the canal, which required Kootenay Canal plant shutdown during the entire outage period. To facilitate the canal outage, an agreement was made between the Canadian and U.S. Entities, Bonneville Power Administration and B.C. Hydro to provide for the optimal balancing of the storage of water in Libby and Arrow reservoirs from 13 February 2001 through 03 April 2001. As a result of this agreement, 55.54 hm^3 (22.7 ksfd) was stored in Libby reservoir over the period 13 February through to 24 February 2001 with an equal and concurrent release from Arrow reservoir. All the water stored in Libby was released by 3 April 2001 with an equal and concurrent reduction in release from Arrow reservoir.

In preparation for the canal outage, Kootenay Lake was drafted to a low elevation of 530.60 m (1740.8 feet) prior to the start of the outage with an increased in lake discharge. Libby discharge increased beginning 8 February, and that coupled with a constraint on Kootenay Lake discharge during the canal plant outage, resulted in Kootenay Lake rising to an elevation of 530.96 m (1742 .0 feet) on 23 February before drafting to elevation 530.87 m (1741.7 feet) by month end when Libby discharge was reduced. During February 2001, Kootenay Lake discharge ranged from a daily average high of 569.17 m^3/s (20,100 cfs) to a daily average low of 243.52 m^3/s (8,600 cfs).

Kootenay Lake was drafted for all of March as required under the IJC to meet the 1 April limit of 530.14 m (1739.32 feet). Kootenay Lake discharge was adjusted to control the reservoir below the IJC limit while meeting system requirements. Lake discharge averaged 402.10 m^3/s (14,200 cfs) for the month, and by month end, Kootenay Lake elevation was at 529.80 m (1738.2 feet).

Kootenay Lake drafted to a minimum elevation of 529.74 m (1738.0 feet) on 5 April 2001. Kootenay Lake discharge was then kept near inflow until on 27 April 2001, when the Kootenay Lake Board of Control declared the commencement of spring rise on Kootenay. Following the declaration of spring freshet, Kootenay Lake was operated in accordance to the IJC lowering formula. By month end, Kootenay Lake was at elevation 530.17 m (1739.4 feet).

During April 2001, B.C. Hydro, in response to the low runoff volume forecast in the Kootenay basin, requested West Kootenay Power to seek a temporary variance to the IJC Order during 2001. The proposed variance was to cancel the implementation of the IJC lowering formula during the spring freshet while allowing Kootenay Lake to rise no higher than 532.73 m (1747.8 feet). After the freshet, Kootenay Lake would be regulated to a maximum elevation of 531.97 m (1745.32 feet) until 1 September after which the normal IJC Order would apply. The proposed variance was intended to improve the summer elevation of Kootenay Lake resulting in expected power and non-power benefits. On 30 April 2001 the International Kootenay Lake Board of Control approved a very limited variance to the effect that if Kootenay Lake fails to reach elevation 531.36 m (1743.32 feet) during the spring freshet, then the lowering formula operation may be terminated and the reservoir can be raised to elevation 531.40 m (1743.43 feet). The operation of Kootenay Lake during 2001 did not trigger the application of the approved variance.

In May, Kootenay Lake level rose sharply in response to the spring freshet inflow. The inflow peaked at 1795.29 m^3/s (63,400 cfs) on 28 May 2001. Kootenay Lake discharge was increased in accordance with the IJC Order for Kootenay Lake. The monthly average was 580.49 m^3/s (20,500 cfs), with a peak of 1019.41 m^3/s (36,000 cfs) on 31 May 2001. Kootenay Lake reached its maximum elevation for the year of 531.90 m (1745.1 feet) on 29 May 2001, about a month earlier than the previous year.

Beginning in June, Kootenay Lake levels dropped due to receding runoff. The reservoir discharge was kept near inflow in order to control reservoir levels slightly below the IJC limits. The monthly discharge averaged 719.25 m^3/s (25,400 cfs). On 13 June 2001, the Kootenay Lake level at Nelson dropped below the Nelson gauge IJC elevation of 531.36 m (1743.32 feet) and the lake operation remained constrained to less than 531.36 m (1743.32 feet) until 31 August as required by the IJC Order for Kootenay Lake. The month end level at Queen's Bay was 531.39 m (1743.4 feet) and at Nelson, 531.33 m (1743.2 feet). Kootenay Lake drafted in this month with the lowest summer reservoir elevation of 531.21 m (1742.8 feet) occurring on 22 June 2001, about 2 months earlier than the previous year.

For the period July to August, as the Kootenay Lake margin below the IJC limit increased due to receding runoff, Duncan discharge was gradually increased beginning late July to support Kootenay River operations until the end of August. Libby outflow was also increased in July and discharge from Kootenay Lake was correspondingly reduced, averaging at 506.87 m^3/s (17,900 cfs) in July and 475.72 m^3/s (16,800 cfs) in August. Beginning 20 August, when Brilliant G2 was shutdown for runner upgrade work, Kootenay Lake discharge was adjusted to keep Brilliant discharge at 3-units full load (no spill) for the balance of August. Over the period 5 September to 10 September, Kootenay Lake discharge was increased to 736.24 m^3/s (26,000 cfs) in accordance with the Kootenay Lake letter agreement for energy exchange between BC Hydro and BPA.

Storage Transfer Agreements

In July and August of 2000 Libby Reservoir filled from elevation 737.01 m (2418 feet) on 1 July to the highest elevation of the season at 742.58 m (2436.3 feet) on 16 August 2000. During this time Libby released 198.22 m^3/s (7,000 cfs), which was the minimum outflow recommended by the USFWS for bull trout in the Kootenai River. A Libby/Arrow storage exchange was not implemented in 2000 because there was not mutual benefit for the U.S. and Canada.

Similarly in 2001, Lake Koocanusa was more than 6.1 m (twenty feet) below full in July and August and Libby released the minimum outflow of 169.90 m^3/s (6,000 cfs) for bull trout. A Libby/Arrow storage agreement was not reached in 2001 since Arrow reservoir was more than 9.45 m (31 feet) below full as well. Both the U.S. and Canada agreed not to initiate the Libby/Arrow storage exchange under the Libby Coordination Agreement (LCA).

VI Power and Flood Control Accomplishments

General

During the period covered by this report, Duncan, Arrow, and Mica reservoirs were operated for power, flood control, and other benefits in accordance with the Columbia River Treaty and operating plans and agreements described in Section III. Consistent with all DOP's prepared since the installation of generation at Mica, the 2000-01 and 2001-02 DOP's were designed to achieve optimum power generation at-site in Canada and downstream in Canada and the U.S., in accordance with paragraph 7 of Annex A of the Treaty.

During the period covered by this report, Libby reservoir was operated for flood control and other purposes in accordance with the Treaty and the 1999 "Columbia River Treaty Flood Control Operating Plan." During a portion of the year, Libby operated for power purposes according to the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER). During the remainder of the operating year, Libby operated for storage and releases recommended for endangered white sturgeon and salmon by the USFWS and the NMFS Biological Opinions.

Flood Control

The Columbia River Basin reservoir system, including the Columbia River Treaty projects, was not operated for flood control during the 2000 - 2001 winter period, since the weekly agreed-to operations were adequate to accomplish spring flood evacuation control goals. The weekly operation was guided to a large extent by the daily streamflow and reservoir simulations and to a lesser degree by the charts in the Flood Control Operating Plan. There was never any real potential for flooding. Due to a near record low runoff flood control was really never an issue. The unregulated peak flow at The Dalles, Oregon, shown on chart 14, is estimated at 9253.94 m^3/s (326,800 cfs) on 30 May and a regulated flow of 4796.87 m^3/s (169,400 cfs) on 17 May. The unregulated stage at Vancouver, WA was 3.20 m (10.5 feet) on 31 May and the high-observed stage was 1.68 m (5.5 feet) on 1 June.

Chart 15 shows the relative filling of Arrow and Grand Coulee during the filling period and compares the regulation to guide lines, Chart 6, of the Columbia River Treaty Flood Control Operating Plan. Because this year's low April runoff volume was forecast to be near a record low of

53 percent, and Mica was drafted very deeply for power, there were no daily operations specified for Arrow, and the projects were able to meet both fish flow and flood control objectives.

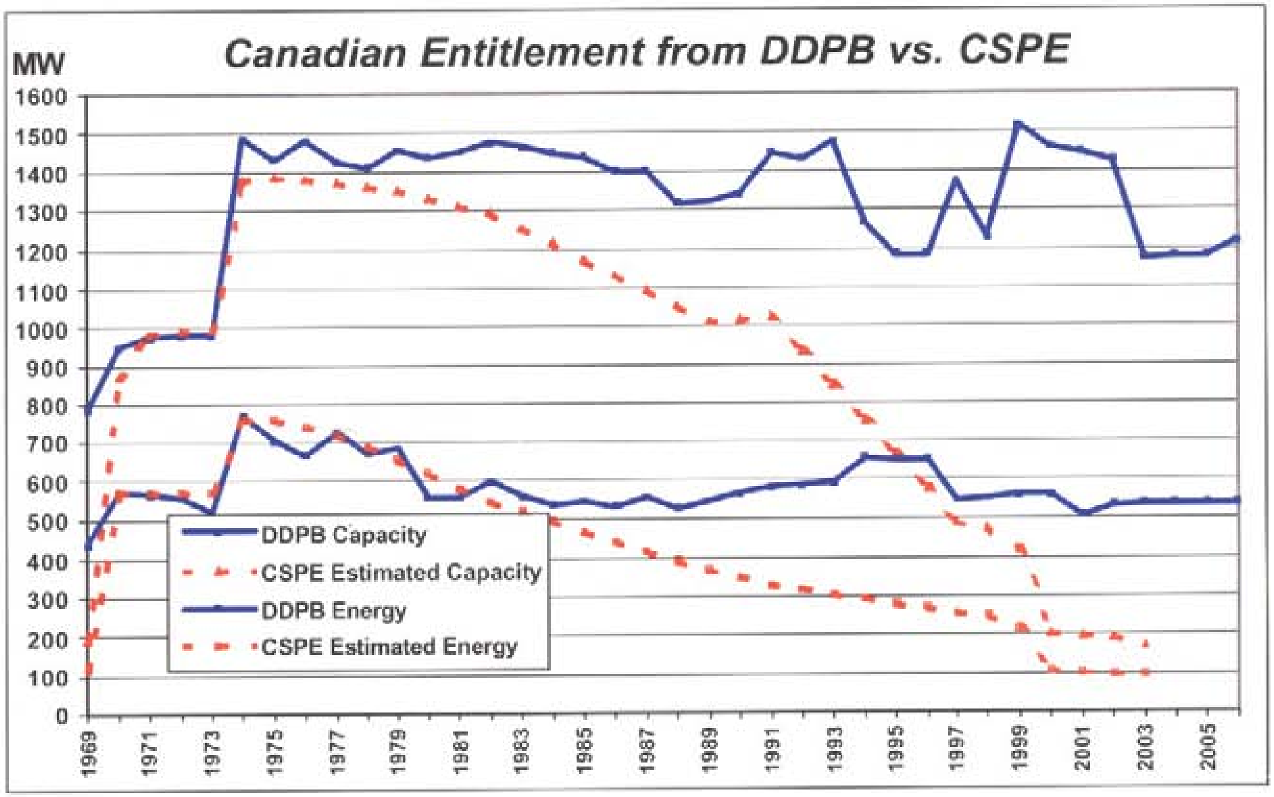
Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the Treaty Flood Control Operating Plan. Computed Initial Controlled Flows at The Dalles were 7277.42 m^3/s (257,000 cfs) on 1 January 2000; 5663.36 m^3/s (200,000 cfs) on 1 February; 5663.36 m^3/s (200,000 cfs) on 1 March; 5663.36 m^3/s (200,000 cfs) on 1 April; and 5663.36 m^3/s (200,000 cfs) on 1 May. As mentioned earlier, the observed peak flow at The Dalles was 4796.87 m^3/s (169,400 cfs) on 17 May. Data for the 1 May ICF computation are given in Table 6.

Canadian Entitlement

From 1 August 2000 through 31 July 2001, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Duncan and Arrow reservoirs to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. The amount returned, not including transmission losses and scheduling adjustments, was 277.4 average MW at rates up to 793.7 MW. No Entitlement power was disposed directly in the U.S. during 1 August 2000 through 31 July 2001, as was allowed by the 29 March 1999 Agreements on "Aspects of the Delivery of the Canadian Entitlement for 4/1/98 Through 9/15/2024" and "Disposals of the Canadian Entitlement Within the U.S. for 4/1/98 Through 9/15/2024." During August and September of 2001 the amount returned was 292.1 aMW at rates up to 782.6 MW.

During the period 1 August 2000 through 31 July 2001, B.C. Hydro did not deliver any energy or capacity to BPA in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement (CEPA). This was because the DDPB's for the 2000/01 and 2001/02 operating years did not show any decrease in U.S. downstream power benefits due to the operation of Canadian storage for optimum power in Canada and the U.S., instead of optimum power only in the U.S.

In accordance with the Canadian Entitlement Exchange Agreement (CEEA) dated 13 August 1964, the U.S. Entity delivered capacity and energy to the Columbia Storage Power Exchange (CSPE) participants based on the 1964 estimates of the Canadian Entitlement to downstream power benefits from the operation of Mica reservoir. Delivery under the CEEA was 99 average megawatts at rates up to 192 MW from 1 August 2000 through 31 March 2001, and 95 average megawatts at rates up to 187 MW from 1 April 2001 through 31 July 2001. The following graph compares the historic Canadian Entitlement computation from the DDPB studies to the amount sold under the CEPA contract.



Power Generation and Other Accomplishments

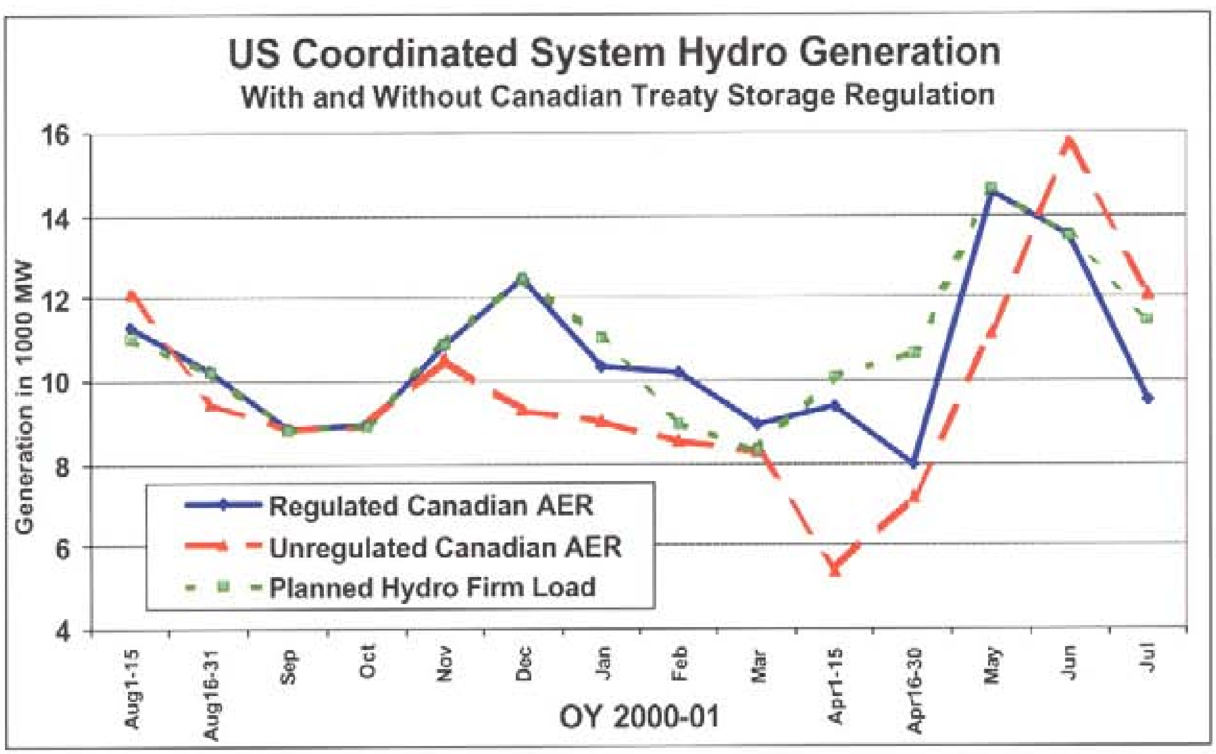
At the beginning of the 2000-01 operating year, the TSR storage level for Canadian storage was 97.7 percent full, and the Coordinated System storage level was 97.07 percent full as measured in the PNCA AER which includes the Canadian Storage operation from the TSR study. Due to the record low unregulated streamflows during operating year, the hydro system operated to draft proportionally well below the ORC from 16 August through July in order to create the firm load carrying capability determined in the critical period studies.

As a result, the U.S. power system did not have significant amounts of nonfirm energy to displace thermal resources or export outside the region, as is usually the case in normal and better water years. Instead, most Pacific Northwest (PNW) utilities attempted to purchase energy from outside the region and/or arrange for extensive reductions in their firm load requirements - mainly from large industrial customers. The ability to purchase energy was limited by a related power shortage in California and the resulting high energy prices. As a last resort, some of the

Columbia River fishery related operating requirements were reduced in order to increase hydropower generation and assure that PNW firm loads could be met

During the late spring of 2001, concerns about extremely low summer reservoir levels at Canadian projects led the Entities to complete a Summer Treaty Storage (STS) agreement that ~~that~~ enabled the U.S. Entity to store almost 4.9 km³ (4 Maf) in Canadian reservoirs. This storage increased the coordinated power system reliability during the following fall and winter. On 31 July 2001, actual Canadian storage levels reached 65.7 percent full compared to only 49.9 percent full in the DOP TSR. The AER coordinated system storage level reached 67.07 percent full on 31 July 2001.

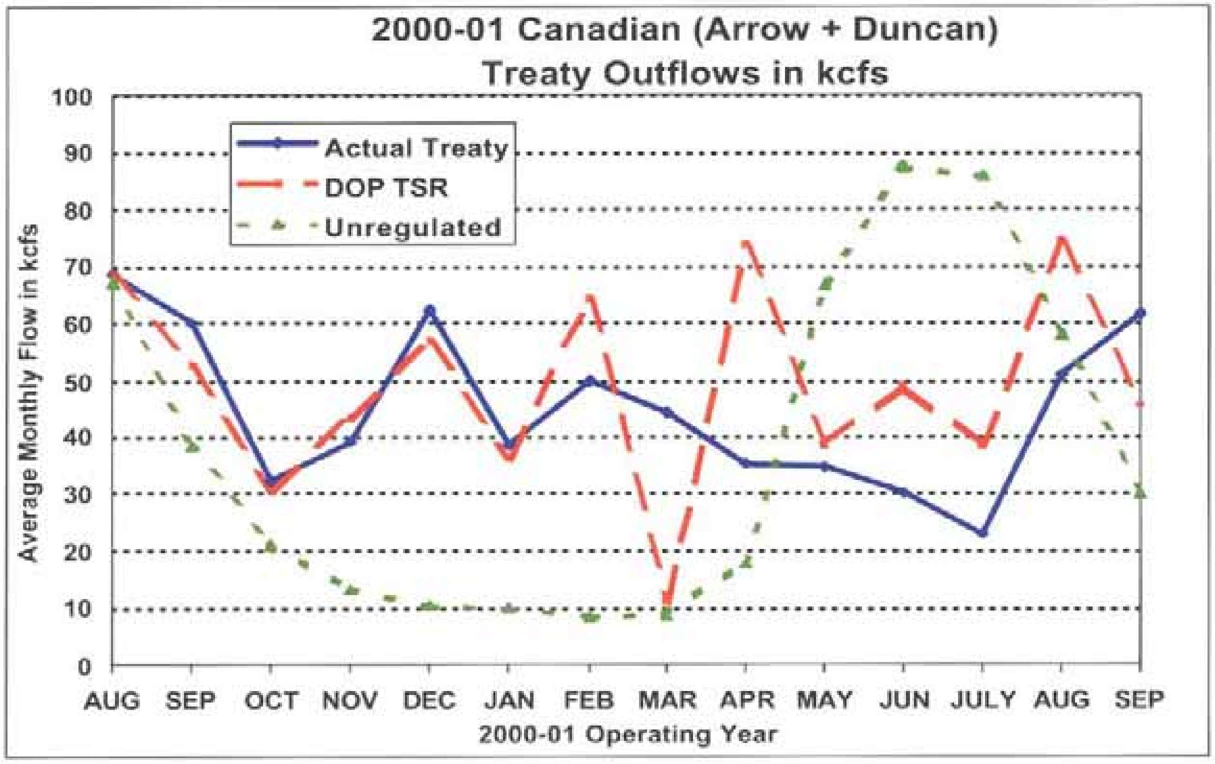
Actual U.S. power benefits from the operation of Treaty storage are unknown due to the complicated nature of hourly power operations and the need to speculate on alternative operating procedures, nonpower requirements, loads and resources, and market conditions in the absence of Treaty storage. However, the following graph shows a rough estimate of the average monthly impact on downstream U.S. power generation during the 2000-01 operating year, with and without the regulation of Canadian Treaty storage, based on the PNCA AER that includes minimum flow and spill requirements for U.S. fishery objectives. The increase in U.S. power generation due to the operation of Canadian storage, as measured by the PNCA AER, was 675 aMW. This power benefit would have been 925 aMW if measured without U.S. fishery requirements.



Based on the authority from the 2000-01 and 2001-02 DOPs, the Operating Committee completed several supplemental operating agreements, described in Section III, which resulted in power and other benefits both in Canada and the U.S. Other benefits include increased reservoir levels for summer recreation and dust storm avoidance and changes to streamflows below Arrow that enhanced trout and white fish spawning and the downstream migration of salmon. The following graph shows the difference in Arrow plus Duncan average monthly regulated outflows between the DOP TSR and the actual Treaty flows due to these agreements. The unregulated stream flow is also shown for comparison purposes.

As of 30 September 2000, the sum of Canadian Treaty storage was positioned 538.3 hm^3 (220 ksfd) below the DOP TSR. The U.S. Entity had exercised 489.3 hm^3 (200 ksfd) of provisional draft rights during September per the terms of the Whitefish Agreement, and the Canadian Entity had drafted 48.9 hm^3 (20 ksfd) under the terms of the LCA.

In October 2000, the U.S. drafted an additional 244.7 hm^3 (100 ksfd) from Arrow to increase the Grand Coulee forebay level and Canada returned the LCA draft, such that the sum of Canadian Treaty storage was positioned 734 hm^3 (300 ksfd) below the DOP TSR. Beginning mid November, the U.S. drafted an additional 122.3 hm^3 (50 ksfd) and Canada drafted 205.5 hm^3 (84 ksfd) under the LCA to finish the month 1,061.8 hm^3 (434 ksfd) below the DOP TSR. The U.S. returned 122.3 hm^3 (50 ksfd) of provisional draft during December to finish the year at 939.5 hm^3 (384 ksfd) below the DOP TSR.



Beginning January 2001, Arrow's actual discharge was reduced to about 97.9 hm^3 (40 kcfs) and Canada and the U.S. agreed to shape flow across the January through April timeframe to meet multiple system requirements and fishery needs. Due to the low runoff volume forecast in January, Treaty discharge on the TSR was considerably reduced which resulted in a draft below TSR for the month of January. The combination of January draft and LCA provisional draft resulted in Treaty storage being positioned over 1223,3 hm^3 (500 ksfd) below the TSR at the end of January. During February and March, flow was maintained to protect whitefish and the U.S. did not store flow augmentation since space was available in U.S. reservoirs because of deep winter draft to meet load.

Beginning in April, discharge from Arrow was set to 85.6 hm^3 (35 kcfs) to balance the needs of BC trout spawning, U.S. Vernita Bar requirements, and system load requirements. All provisional draft was returned by the end of April. In May, Arrow discharge was reduced to 73.4 hm^3 (30 kcfs) to store water for a summer storage agreement to meet U.S. fall/winter reliability requirements and to increase the reservoir level at Arrow during the summer and fall. By the end of July, further reductions in Arrow's discharge had increased the storage amount to in excess of 2935.9 hm^3 (1200 ksfd). Storage continued in August, and the Summer Treaty Storage (STS) account reached a maximum level of 4898.1 hm^3 (2002 ksfd) on 31 August. Release from the Summer Treaty Storage account began in September.

Table 1
Unregulated Runoff Volume Forecasts
Million of Acre -feet
2001

Forecast Date- 1st of	Duncan Most Probable 1 April- 31-Aug	Arrow Most Probable 1 April- 31-Aug	Mica Most Probable 1 April- 31-Aug	Libby Most Probable 1 April- 31-Aug	Columbia River at The Dalles, Oregon Most Probable 1 April- 31-Aug
January	1.77	19.3	9.8	4.76	70.8
February	1.67	17.2	9.0	3.94	59.8
March	1.62	16.6	8.7	3.37	52.2
April	1.61	17.0	8.8	3.32	49.6
May	1.57	16.3	8.5	3.51	50.1
June	1.59	16.1	8.5	3.16	49.0
Actual	1.6	17.7	8.8	3.17	52.8

NOTE: These data were used in actual operations. Subsequent revisions have been made in some cases.

Combined with previous page

Table 1M
Unregulated Runoff Volume Forecasts
Cubic Kilometers and Millions of Acre -feet
2001

Columbia River @

Forecast Date 1st of	Duncan Most Probable 1 Apr - 31 Aug km³	Maf	Arrow Most Probable 1 Apr - 31 Aug km³	Maf	Mica Most Probable 1 Apr - 31 Aug km³	Maf	Libby Most Probable 1 Apr - 31 Aug km³	Maf	The Dalles, OR Most Probable 1 Apr - 31 Aug km³	Maf
January	2.18	1.77	23.81	19.3	12.09	9.8	5.87	4.76	87.33	70.8
February	2.06	1.67	21.22	17.2	11.10	9.0	4.86	3.94	73.76	59.8
March	2.00	1.62	20.48	16.6	10.73	8.7	4.16	3.37	64.39	52.2
April	1.99	1.61	20.96	17.0	10.85	8.8	4.10	3.32	61.18	49.6
May	1.94	1.57	20.11	16.3	10.48	8.5	4.33	3.51	61.80	50.1
June	1.96	1.59	19.86	16.1	10.48	8.5	3.90	3.16	60.44	49.0
Actual	1.97	1.60	21.83	17.7	10.85	8.8	3.91	3.17	65.13	52.8

Note: These data were used in actual operations. Subsequent revisions have been made in some cases.

TABLE 2
2001 Variable Refill Curve
Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			8130.4	7473.8	7081.5	6985.0	6367.6	5099.9
PROBABLE DATE-31JULY INFLOW,KSFD	**		4099.0	3768.0	3570.2	3521.6	3210.3	2571.2
95% FORECAST ERROR FOR DATE, KSFD			653.0	510.4	465.4	444.5	360.5	360.5
95% CONF.DATE-31JULY INFLOW,KSFD	1/		3446.0	3257.6	3104.8	3077.0	2849.8	2210.7
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		3446.0					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		9800.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		2746.5					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		2829.7					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		2456.5					
JAN31 ECC,FT.	7/		2447.4					
BASE ECC, FT		2447.4						
LOWER LIMIT,FT		2409.4						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		3363.3	3179.4				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		9800.0	10000.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		2471.8	2480.0				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		2637.7	2829.8				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		2452.7	2456.4				
FEB28 ECC,FT.	7/		2437.6	2437.6				
BASE ECC,FT		2437.6						
LOWER LIMIT,FT		2401.8						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		3277.1	3097.9	3024.1			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		9900.0	10000.0	10000.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		2167.5	2170.0	2170.0			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		2419.6	2601.3	2675.1			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		2448.3	2451.9	2453.5			
MAR31 ECC,FT.	7/		2430.7	2430.7	2430.7			
BASE ECC,FT		2430.7						
LOWER LIMIT,FT		2397.0						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		3101.4	2931.8	2862.6	2913.9		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		19900.0	20000.0	20000.0	20000.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		1838.3	1840.0	1840.0	1840.0		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		2266.2	2437.4	2506.6	2455.3		
MIN APR30 RESERVOIR CONTENT,FEET	6/		2445.2	2448.7	2450.1	2449.0		
APR30 ECC,FT.	7/		2416.6	2416.6	2416.6	2416.6		
BASE ECC,FT		2416.6						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		2467.3	2332.4	2275.8	2317.0	2265.6	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		20000.0	20000.0	20000.0	20000.0	20000.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		1220.0	1220.0	1220.0	1220.0	1220.0	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		2281.9	2416.8	2473.4	2432.2	2483.6	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		2445.5	2448.3	2449.4	2448.6	2449.6	
MAY31 ECC,FT.	7/		2422.3	2422.3	2422.3	2422.3	2422.3	
BASE ECC,FT		2422.3						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			35.5	35.5	36.3	37.3	39.4	49.5
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		1223.3	1156.4	1127.0	1147.7	1122.8	1094.3
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		20000.0	20000.0	20000.0	20000.0	20000.0	20000.0
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		620.0	620.0	620.0	620.0	620.0	620.0
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		2925.9	2992.8	3022.2	3001.5	3026.4	3054.9
MIN JUN30 RESERVOIR CONTENT,FEET	6/		2458.4	2459.8	2460.3	2459.9	2460.4	2461.0
JUN30 ECC,FT.	7/		2449.8	2449.8	2449.8	2449.8	2449.8	2449.8
BASE ECC,FT		2449.8						
JUL 31 ECC, FT			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (3529.2 KSFD) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 2M

2001 Variable Refill Curve

Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			10.0	9.2	8.7	8.6	7.9	6.3
PROBABLE DATE-31JULY INFLOW, HM^3	**		10028.6	9218.8	8734.9	8615.8	7854.3	6290.6
95% FORECAST ERROR FOR DATE,IN HM^3			1597.7	1248.9	1138.6	1087.6	881.9	881.9
95% CONF.DATE-31JULY INFLOW, HM^3	1/		8430.9	7969.9	7596.3	7528.2	6972.4	5408.7
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		8431.0					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		277.5					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/							
MIN JAN31 RESERVOIR CONTENT, HM^3	5/		6923.1					
MIN JAN31 RESERVOIR CONTENT, METERS	6/		748.7					
JAN31 ECC, M	7/		746.0					
BASE ECC, M		746.0						
LOWER LIMIT, M		734.4						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		8228.6	7778.7				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		277.5	283.2				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		6047.5	6067.6				
MIN FEB28 RESERVOIR CONTENT, HM^3	5/		6453.4	6923.4				
MIN FEB28 RESERVOIR CONTENT, M	6/		747.6	748.7				
FEB28 ECC, M	7/		743.0	743.0				
BASE ECC, M		743.0						
LOWER LIMIT, M		732.1						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		8017.8	7579.3	7398.8			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		280.3	283.2	283.2			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		5303.1	5309.1	5309.1			
MIN MAR31 RESERVOIR CONTENT, HM^3	5/		5919.8	6364.3	6544.9			
MIN MAR31 RESERVOIR CONTENT, M	6/		746.2	747.3	747.8			
MAR31 ECC, M	7/		740.9	740.9	740.9			
BASE ECC, M		740.9						
LOWER LIMIT, M		730.6						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		7587.9	7172.9	7003.6	7129.1		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		563.5	566.3	566.3	566.3		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		4497.7	4501.7	4501.7	4501.7		
MIN APR30 RESERVOIR CONTENT, HM^3	5/		5544.4	5963.3	6132.5	6007.1		
MIN APR30 RESERVOIR CONTENT, M	6/		745.3	746.4	746.8	746.5		
APR30 ECC, M	7/		736.6	736.6	736.6	736.6		
BASE ECC, M		736.6						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		6036.5	5706.4	5568.0	5668.8	5543.0	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		566.3	566.3	566.3	566.3	566.3	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		2984.9	2984.9	2984.9	2984.9	2984.9	
MIN MAY31 RESERVOIR CONTENT, HM^3	5/		5582.8	5912.9	6051.3	5950.6	6076.3	
MIN MAY31 RESERVOIR CONTENT, M	6/		745.4	746.2	746.6	746.3	746.6	
MAY31 ECC, M	7/		738.3	738.3	738.3	738.3	738.3	
BASE ECC, M		738.3						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			35.5	35.5	36.3	37.3	39.4	49.5
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		2993.0	2829.3	2757.4	2808.0	2747.1	2677.3
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		566.3	566.3	566.3	566.3	566.3	566.3
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		1516.9	1516.9	1516.9	1516.9	1516.9	1516.9
MIN JUN30 RESERVOIR CONTENT, HM^3	5/		7158.5	7322.1	7394.0	7343.4	7404.3	7474.1
MIN JUN30 RESERVOIR CONTENT, M	6/		749.3	749.7	749.9	749.8	749.9	750.1
JUN30 ECC, M	7/		746.7	746.7	746.7	746.7	746.7	746.7
BASE ECC, M		746.7						
JUL 31 ECC, M			752.9	752.9	752.9	752.9	752.9	752.9

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT. 5/ FULL CONTENT (8634.5 HM^3) MINUS 2/ PLUS 3/ MINUS /4.
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR ELEV DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 3
2001 Variable Refill Curve
Arrow Reservoir

		INITIAL	**JAN 1 Local**	**FEB 1 Local**	**MAR 1 Local**	**APR 1 Total**	**MAY 1 Total**	**JUN 1 Total**
PROBABLE DATE-31JULY INFLOW,KAF			8719.5	7503.6	7123.4	14107.2	12595.6	9410.3
& IN KSFD	**		4396.0	3783.0	3591.3	7112.3	6350.2	4744.3
95% FORECAST ERROR FOR DATE,IN KSFD			762.0	632.8	505.1	715.6	501.7	501.7
95% CONF.DATE-31JULY INFLOW,KSFD	1/		3634.0	3150.2	3086.3	6396.7	5848.5	4242.6
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		3634.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	3/		5714.8					
UPSTREAM DISCHARGE,KSFD	4/		2763.4					
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		2897.0					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		1433.3					
JAN31 ECC,FT.	7/		1431.2					
BASE ECC, FT		1439.3						
LOWER LIMIT, FT		1412.1						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.3	97.3				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		3535.9	3065.1				
MIN MAR1-JUL31 OUTFLOW,KSFD	3/		5166.0	5216.0				
UPSTREAM DISCHARGE,KSFD	4/		2119.4	2115.5				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		3090.3	3579.6				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		1426.4	1444.0				
FEB28 ECC,FT.	7/		1426.4	1431.5				
BASE ECC, FT		1431.5						
LOWER LIMIT, FT		1401.1						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			93.9	93.9	96.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		3412.4	2958.0	2975.2			
MIN APR1-JUL31 OUTFLOW,KSFD	3/		4498.1	4534.0	4534.0			
UPSTREAM DISCHARGE,KSFD	4/		1437.4	1278.5	1429.4			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		3227.9	3579.6	3579.6			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		1438.6	1444.0	1444.0			
MAR31 ECC,FT.	7/		1420.1	1420.1	1420.1			
BASE ECC,FT		1420.1						
LOWER LIMIT, FT		1382.1						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			85.3	85.3	87.6	92.6		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		3099.8	2687.1	2703.6	5923.4		
MIN MAY1-JUL31 OUTFLOW,KSFD	3/		3683.9	3709.0	3709.0	3709.0		
UPSTREAM DISCHARGE,KSFD	4/		920.0	920.0	920.0	2585.9		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		3243.7	3579.6	3579.6	3579.6		
MIN APR30 RESERVOIR CONTENT,FEET	6/		1438.8	1444.0	1444.0	1444.0		
APR30 ECC,FT.	7/		1418.5	1418.5	1418.5	1418.5		
BASE ECC, FT		1418.5						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			59.9	59.9	61.5	69.3	74.9	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		2176.8	1886.9	1898.1	4432.9	4380.5	
MIN JUN1-JUL31 OUTFLOW,KSFD	3/		2608.8	2624.0	2624.0	2624.0	2624.0	
UPSTREAM DISCHARGE,KSFD	4/		610.0	610.0	610.0	2336.1	2336.1	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		3401.6	3579.6	3579.6	3579.6	3579.6	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		1441.3	1444.0	1444.0	1444.0	1444.0	
MAY31 ECC,FT.	7/		1429.0	1429.0	1429.0	1429.0	1429.0	
BASE ECC,FT		1429.0						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			25.6	25.6	26.3	32.1	34.7	46.3
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		930.3	806.4	811.7	2053.3	2029.4	1964.3
MIN JUL1-JUL31 OUTFLOW,KSFD	3/		1356.0	1364.0	1364.0	1364.0	1364.0	1364.0
UPSTREAM DISCHARGE,KSFD	4/		310.0	310.0	310.0	1037.6	1037.6	1037.6
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		3579.6	3579.6	3579.6	3579.6	3579.6	3579.6
MIN JUN30 RESERVOIR CONTENT,FEET	6/		1444.0	1444.0	1444.0	1444.0	1444.0	1444.0
JUN30 ECC,FT.	7/		1440.0	1440.0	1440.0	1441.6	1441.6	1441.6
BASE ECC,FT		1441.6						
JUL 31 ECC, FT			1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEDING LINE TIMES 1/.
3/ CUMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT. 5/ FULL CONTENT (3579.6 KSFD) MINUS 2/ PLUS 3/ MINUS /4.
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR ELEV DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 3M

2001 Variable Refill Curve

Arrow Reservoir

		INITIAL	JAN 1 Local	FEB 1 Local	MAR 1 Local	APR 1 Total	MAY 1 Total	JUN 1 Total
PROBABLE DATE-31JULY INFLOW, KM^3			10.8	9.3	8.8	17.4	15.5	11.6
& IN HM^3	**		10755.3	9255.5	8786.6	17401.0	15536.4	11607.4
95% FORECAST ERROR FOR DATE,IN HM^3			1864.2	1548.3	1235.7	1750.8	1227.5	1227.5
95% CONF.DATE-31JULY INFLOW, HM^3	1/		8891.0	7707.2	7550.9	15650.2	14308.9	10379.9
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		8890.9					
MIN FEB1-JUL31 OUTFLOW, HM^3	3/		13981.8					
UPSTREAM DISCHARGE, HM^3	4/		6760.9					
MIN JAN31 RESERVOIR CONTENT, HM^3	5/		7087.8					
MIN JAN31 RESERVOIR CONTENT, METERS	6/		436.9					
JAN31 ECC, M	7/		436.2					
BASE ECC, M		438.7						
LOWER LIMIT, M		430.4						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.3	97.3				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		8650.9	7499.1				
MIN MAR1-JUL31 OUTFLOW, HM^3	3/		12639.1	12761.5				
UPSTREAM DISCHARGE, HM^3	4/		5185.3	5175.8				
MIN FEB28 RESERVOIR CONTENT, HM^3	5/		7560.7	8757.8				
MIN FEB28 RESERVOIR CONTENT, M	6/		434.8	440.1				
FEB28 ECC, M	7/		434.8	436.3				
BASE ECC, M		436.3						
LOWER LIMIT, M		427.1						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			93.9	93.9	96.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		8348.8	7237.0	7279.1			
MIN APR1-JUL31 OUTFLOW, HM^3	3/		11005.0	11092.9	11092.9			
UPSTREAM DISCHARGE, HM^3	4/		3516.7	3128.0	3497.2			
MIN MAR31 RESERVOIR CONTENT, HM^3	5/		7897.3	8757.8	8757.8			
MIN MAR31 RESERVOIR CONTENT, M	6/		438.5	440.1	440.1			
MAR31 ECC, M	7/		432.8	432.8	432.8			
BASE ECC, M		432.8						
LOWER LIMIT, M		421.3						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			85.3	85.3	87.6	92.6		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		7584.0	6574.3	6614.6	14492.2		
MIN MAY1-JUL31 OUTFLOW, HM^3	3/		9013.0	9074.4	9074.4	9074.4		
UPSTREAM DISCHARGE, HM^3	4/		2250.9	2250.9	2250.9	6326.7		
MIN APR30 RESERVOIR CONTENT, HM^3	5/		7936.0	8757.8	8757.8	8757.8		
MIN APR30 RESERVOIR CONTENT, M	6/		438.5	440.1	440.1	440.1		
APR30 ECC, M	7/		432.4	432.4	432.4	432.4		
BASE ECC, M		432.4						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			59.9	59.9	61.5	69.3	74.9	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		5325.8	4616.5	4643.9	10845.5	10717.3	
MIN JUN1-JUL31 OUTFLOW, HM^3	3/		6382.7	6419.9	6419.9	6419.9	6419.9	
UPSTREAM DISCHARGE, HM^3	4/		1492.4	1492.4	1492.4	5715.5	5715.5	
MIN MAY31 RESERVOIR CONTENT, HM^3	5/		8322.4	8757.8	8757.8	8757.8	8757.8	
MIN MAY31 RESERVOIR CONTENT, M	6/		439.3	440.1	440.1	440.1	440.1	
MAY31 ECC, M	7/		435.6	435.6	435.6	435.6	435.6	
BASE ECC, M		435.6						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			25.6	25.6	26.3	32.1	34.7	46.3
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		2276.1	1972.9	1985.9	5023.6	4965.1	4805.9
MIN JUL1-JUL31 OUTFLOW, HM^3	3/		3317.6	3337.2	3337.2	3337.2	3337.2	3337.2
UPSTREAM DISCHARGE, HM^3	4/		758.4	758.4	758.4	2538.6	2538.6	2538.6
MIN JUN30 RESERVOIR CONTENT, HM^3	5/		8757.8	8757.8	8757.8	8757.8	8757.8	8757.8
MIN JUN30 RESERVOIR CONTENT, M	6/		440.1	440.1	440.1	440.1	440.1	440.1
JUN30 ECC, M	7/		438.9	438.9	438.9	439.4	439.4	439.4
BASE ECC, M		439.4						
JUL 31 ECC, M			440.1	440.1	440.1	440.1	440.1	440.1

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS 8757.8
4/ UPSTREAM DISCHARGE REQUIREMENT. 5/ FULL CONTENT (8757.8 HM^3) MINUS 2/ PLUS 3/ MINUS /4.
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR ELEV DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 4
2001 Variable Refill Curve
Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			1531.3	1440.0	1361.8	1321.3	1208.4	926.5
& IN KSFD	**		772.0	726.0	686.6	666.1	609.2	467.1
95% FORECAST ERROR FOR DATE,IN KSFD			118.4	108.9	97.5	88.1	73.3	73.3
95% CONF.DATE-31JULY INFLOW,KSFD	1/		653.6	617.1	589.0	578.0	535.9	393.8
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		653.6					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		290.3					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		342.5					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		1848.5					
JAN31 ECC,FT	7/		1845.7					
BASE ECC,FT		1845.3						
LOWER LIMIT, FT		1794.5						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		639.3	603.5				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		263.0	266.2				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		329.5	368.5				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		1846.8	1851.8				
FEB28 ECC,FT.	7/		1826.0	1833.6				
BASE ECC,FT		1841.7						
LOWER LIMIT, FT		1794.0						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		622.9	588.0	573.7			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		232.7	235.2	235.2			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		315.6	353.0	367.3			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		1844.9	1849.9	1851.7			
MAR31 ECC,FT.	7/		1826.0	1833.6	1837.1			
BASE ECC,FT		1837.7						
LOWER LIMIT, FT		1794.0						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		583.0	550.4	536.6	540.5		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		200.0	200.0	200.0	200.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		188.7	190.2	190.2	190.2		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		311.5	345.6	359.4	355.5		
MIN APR30 RESERVOIR CONTENT,FEET	6/		1844.4	1848.9	1850.6	1850.1		
APR30 ECC,FT.	7/		1826.0	1833.6	1835.6	1835.6		
BASE ECC,FT		1835.6						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		441.9	417.1	407.0	409.8	406.2	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		200.0	200.0	200.0	200.0	200.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		127.9	128.2	128.2	128.2	128.2	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		391.8	416.9	427.0	424.2	427.8	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		1854.8	1857.9	1859.2	1858.9	1859.3	
MAY31 ECC,FT.	7/		1850.7	1850.7	1850.7	1850.7	1850.7	
BASE ECC,FT		1850.7						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			31.7	31.7	32.4	33.3	35.6	46.9
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		207.2	195.6	190.8	192.5	190.8	184.7
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		200.0	200.0	200.0	200.0	200.0	200.0
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		68.0	68.2	68.2	68.2	68.2	68.2
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		566.6	578.4	583.2	581.5	583.2	589.3
MIN JUN30 RESERVOIR CONTENT,FEET	6/		1876.0	1877.4	1878.0	1877.8	1878.0	1878.7
JUN30 ECC,FT.	7/		1876.0	1876.7	1876.7	1876.7	1876.7	1876.7
BASE ECC,FT		1876.7						
JUL 31 ECC, FT..................			1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (705.8 KSFD) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 4M

2001 Variable Refill Curve

Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			1.9	1.8	1.7	1.6	1.5	1.1
& IN HM^3	**		1888.8	1776.2	1679.7	1629.8	1490.6	1142.8
95% FORECAST ERROR FOR DATE,IN HM^3			289.6	266.6	238.6	215.5	179.3	179.3
95% CONF.DATE-31JULY INFLOW, HM^3	1/		1599.2	1509.7	1441.1	1414.2	1311.2	963.5
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		1599.2					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.8					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/							
MIN JAN31 RESERVOIR CONTENT, HM^3	5/		837.9					
MIN JAN31 RESERVOIR CONTENT, METERS	6/		563.4					
JAN31 ECC, M	7/		562.6					
BASE ECC, M		562.4						
LOWER LIMIT, M		547.0						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		1564.0	1476.5				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.8	2.8				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		643.4	651.3				
MIN FEB28 RESERVOIR CONTENT, HM^3	5/		806.2	901.6				
MIN FEB28 RESERVOIR CONTENT, M	6/		562.9	564.4				
FEB28 ECC, M	7/		556.6	558.9				
BASE ECC, M		561.4						
LOWER LIMIT, M		546.8						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		1524.0	1438.7	1403.7			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.8	2.8	2.8			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		569.4	575.4	575.4			
MIN MAR31 RESERVOIR CONTENT, HM^3	5/		772.2	863.5	898.6			
MIN MAR31 RESERVOIR CONTENT, M	6/		562.3	563.8	564.4			
MAR31 ECC, M	7/		556.6	558.9	559.9			
BASE ECC, M		560.1						
LOWER LIMIT, M		546.8						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		1426.5	1346.6	1312.9	1322.3		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		5.7	5.7	5.7	5.7		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		461.7	465.3	465.3	465.3		
MIN APR30 RESERVOIR CONTENT, HM^3	5/		762.1	845.5	879.3	869.8		
MIN APR30 RESERVOIR CONTENT, M	6/		562.2	563.5	564.1	563.9		
APR30 ECC, M	7/		556.6	558.9	559.5	559.5		
BASE ECC, M		559.5						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		1081.0	1020.5	995.8	1002.7	993.9	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		5.7	5.7	5.7	5.7	5.7	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		312.9	313.7	313.7	313.7	313.7	
MIN MAY31 RESERVOIR CONTENT, HM^3	5/		958.6	1019.9	1044.6	1037.8	1046.6	
MIN MAY31 RESERVOIR CONTENT, M	6/		565.3	566.3	566.7	566.6	566.7	
MAY31 ECC, M	7/		564.1	564.1	564.1	564.1	564.1	
BASE ECC, M		564.1						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			31.7	31.7	32.4	33.3	35.6	46.9
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		506.9	478.6	466.9	470.9	466.8	451.9
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		5.7	5.7	5.7	5.7	5.7	5.7
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		166.5	166.9	166.9	166.9	166.9	166.9
MIN JUN30 RESERVOIR CONTENT, HM^3	5/		1386.3	1415.1	1426.7	1422.7	1426.9	1441.8
MIN JUN30 RESERVOIR CONTENT, M	6/		571.8	572.2	572.4	572.4	572.4	572.6
JUN30 ECC, M	7/		571.8	572.0	572.0	572.0	572.0	572.0
BASE ECC, M		572.0						
JUL 31 ECC, M			576.7	576.7	576.7	576.7	576.7	576.7

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS 8757.8
4/ UPSTREAM DISCHARGE REQUIREMENT. 5/ FULL CONTENT (1726.8 HM^3) MINUS 2/ PLUS 3/ MINUS /4.
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR ELEV DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 5
2001 Variable Refill Curve
Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			4936.0	4138.0	3576.0	3484.0	3657.0	3338.0
PROBABLE DATE-31JULY INFLOW,KSFD			2488.6	2086.2	1802.9	1756.5	1843.7	1682.9
95% FORECAST ERROR FOR DATE, KSFD			886.8	606.4	552.5	533.4	474.5	367.5
OBSERVED JAN1-DATE INFLOW, IN KSFD			0.0	77.6	151.8	235.4	348.4	859.6
95% CONF.DATE-31JULY INFLOW,KSFD	1/		1601.8	1402.2	1098.6	987.7	1020.8	455.8
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			97.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		1553.1					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		4000.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		1107.0					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		2064.4					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		2439.1					
JAN31 ECC,FT.	7/		2413.2					
BASE ECC, FT		2413.2						
LOWER LIMIT,FT		2381.4						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			94.2	97.1				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		1508.6	1362.1				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		4000.0	4000.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		995.0	995.0				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		1996.9	2143.4				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		2435.9	2442.8				
FEB28 ECC,FT.	7/		2410.5	2410.5				
BASE ECC,FT		2410.5						
LOWER LIMIT,FT		2331.0						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			90.8	93.7	96.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		1454.6	1313.3	1059.3			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		4000.0	4000.0	4000.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		871.0	871.0	871.0			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		1926.9	2068.2	2322.2			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		2432.6	2439.3	2450.8			
MAR31 ECC,FT.	7/		2407.5	2407.5	2407.5			
BASE ECC,FT		2406.7						
LOWER LIMIT,FT		2287.2						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			82.7	85.3	87.8	91.1		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		1324.7	1195.9	964.6	899.5		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		7000.0	7000.0	7000.0	7000.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		736.0	736.0	736.0	736.0		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		1921.8	2050.6	2281.9	2347.0		
MIN APR30 RESERVOIR CONTENT,FEET	6/		2432.4	2438.5	2449.0	2451.9		
APR30 ECC,FT.	7/		2406.5	2406.5	2406.5	2406.5		
BASE ECC,FT		2406.5						
		2287.0						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			55.3	57.0	58.7	60.9	66.9	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		885.5	799.5	644.9	601.3	682.4	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		8000.0	8000.0	8000.0	8000.0	8000.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		519.0	519.0	519.0	519.0	519.0	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		2144.0	2230.0	2384.6	2428.2	2347.1	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		2442.8	2446.7	2453.5	2455.4	2451.9	
MAY31 ECC,FT.	7/		2430.3	2430.3	2430.3	2430.3	2430.3	
BASE ECC,FT		2430.3						
		2287.0						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			19.6	20.2	20.8	21.6	23.7	35.5
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		314.0	283.5	228.6	213.1	241.9	161.6
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		9000.0	9000.0	9000.0	9000.0	9000.0	9000.0
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		279.0	279.0	279.0	279.0	279.0	279.0
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		2475.5	2506.0	2510.5	2510.5	2510.5	2510.5
MIN JUN30 RESERVOIR CONTENT,FEET	6/		2457.5	2458.8	2459.0	2459.0	2459.0	2459.0
JUN30 ECC,FT.	7/		2452.6	2452.6	2452.6	2452.6	2452.6	2452.6
BASE ECC,FT		2452.6						
		2287.0						
JUL 31 ECC, FT			2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		104.0	110.0	106.0	105.0	105.0	103.0

1/ Prob. Qin minus (95% error & Jan1-date Qin) minus oberved Qin. 2/precede. line times 1/. 3/ power discharge req. 4/ cum. min. Qout from 3/, date to July. 5/ full content (2510.5 KSFD) plus 4/ minus /2. 6/ elev. from 5/, interp from storage content table A143. 7/Lower of elev. From 6/ or base ECC determined prior to year (initial), but not less than lower limit. 8/ used to calculate the power discharge req for 3/.

TABLE 5M

2001 Variable Refill Curve

Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			6.1	5.1	4.4	4.3	4.5	4.1
PROBABLE DATE-31JULY INFLOW, HM^3	**		6088.6	5104.1	4411.0	4297.5	4510.8	4117.4
95% FORECAST ERROR FOR DATE,IN HM^3			2169.6	1483.6	1351.7	1305.0	1160.9	899.1
OBSERVED JAN1-DATE INFLOW, IN HM^3	1/		0.0	189.9	371.4	575.9	852.4	2103.1
95% CONF.DATE-31JULY INFLOW, HM^3	1/		3919.0	3430.6	2687.8	2416.5	2497.5	1115.2
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			97.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		3799.8					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/							
MIN JAN31 RESERVOIR CONTENT, HM^3	5/		5050.8					
MIN JAN31 RESERVOIR CONTENT, METERS	6/		743.4					
JAN31 ECC, M	7/		735.5					
BASE ECC, M		735.5						
LOWER LIMIT, M		725.9						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			94.2	97.1				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		3690.9	3332.5				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		2434.4	2434.4				
MIN FEB28 RESERVOIR CONTENT, HM^3	5/		4885.6	5244.0				
MIN FEB28 RESERVOIR CONTENT, M	6/		742.5	744.6				
FEB28 ECC, M	7/		734.7	734.7				
BASE ECC, M		734.7						
LOWER LIMIT, M		710.5						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			90.8	93.7	96.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		3558.8	3213.1	2591.7			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		2131.0	2131.0	2131.0			
MIN MAR31 RESERVOIR CONTENT, HM^3	5/		4714.4	5060.1	5681.5			
MIN MAR31 RESERVOIR CONTENT, M	6/		741.5	743.5	747.0			
MAR31 ECC, M	7/		733.8	733.8	733.8			
BASE ECC, M		733.6						
LOWER LIMIT, M		697.1						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			82.7	85.3	87.8	91.1		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		3241.0	2925.9	2360.0	2200.7		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		198.2	198.2	198.2	198.2		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		1800.7	1800.7	1800.7	1800.7		
MIN APR30 RESERVOIR CONTENT, HM^3	5/		4701.9	5017.0	5582.9	5742.2		
MIN APR30 RESERVOIR CONTENT, M	6/		741.4	743.3	746.5	747.3		
APR30 ECC, M	7/		733.5	733.5	733.5	733.5		
BASE ECC, M		733.5						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			55.3	57.0	58.7	60.9	66.9	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		2166.5	1956.1	1577.8	1471.1	1669.6	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		226.5	226.5	226.5	226.5	226.5	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		1269.8	1269.8	1269.8	1269.8	1269.8	
MIN MAY31 RESERVOIR CONTENT, HM^3	5/		5245.5	5455.9	5834.2	5940.8	5742.4	
MIN MAY31 RESERVOIR CONTENT, M	6/		744.6	745.8	747.8	748.4	747.3	
MAY31 ECC, M	7/		740.8	740.8	740.8	740.8	740.8	
BASE ECC, M		740.8						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			19.6	20.2	20.8	21.6	23.7	35.5
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		768.2	693.6	559.3	521.4	591.8	395.4
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		254.9	254.9	254.9	254.9	254.9	254.9
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		682.6	682.6	682.6	682.6	682.6	682.6
MIN JUN30 RESERVOIR CONTENT, HM^3	5/		6056.6	6131.2	6142.2	6142.2	6142.2	6142.2
MIN JUN30 RESERVOIR CONTENT, M	6/		749.0	749.4	749.5	749.5	749.5	749.5
JUN30 ECC, M	7/		747.6	747.6	747.6	747.6	747.6	747.6
BASE ECC, M		747.6						
JUL 31 ECC, M			749.5	749.5	749.5	749.5	749.5	749.5
JAN1-JUL31 FORECAST,-EARLYBIRD, KM^3			128.3	135.7	130.7	129.5	129.5	127.0

1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW. 2/PRECEEDING LINE TIMES 1/. 3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY. 5/ FULL CONTENT (6142.2 HM^3) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.
8/ USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3/.

Table 6
Computation of Initial Controlled Flow
Columbia River at The Dalles
1 May 2001

1 May Forecast of May-August Unregulated Runoff Volume, Maf		43.4
Less Estimated Depletions, Maf		1.5
Less Upstream Storage Corrections, Maf		22.103
MICA	4.471	
ARROW	5.000	
DUNCAN	1.190	
LIBBY	2.225	
LIBBY + DUNCAN UNDER DRAFT	0.000	
HUNGRY HORSE	1.074	
FLATHEAD LAKE	0.500	
NOXON RAPIDS	0.000	
PEND OREILLE LAKE	0.500	
GRAND COULEE	4.592	
BROWNLEE	0.019	
DWORSHAK	0.853	
JOHN DAY	0.180	
TOTAL	22.103	22.103
Forecast of Adjusted Residual Runoff Volume, Maf		21.297
Computed Initial Control Flow from Chart 1 of Flood Control Operation Plan, 1,000 cfs		200

Table 6M
Computation of Initial Controlled Flow
Columbia River at The Dalles
1 May 2001

	km^3	Maf
1 May Forecast of May-August Unregulated Runoff Volume	53.53	43.4
Less Estimated Depletions	1.85	1.5
Less Unstream Storage Corrections	27.26	22.103
MICA	5.515	4.471
ARROW	6.167	5.000
DUNCAN	1.468	1.190
LIBBY	2.745	2.225
LIBBY + DUNCAN UNDER DRAFT	0.000	0.000
HUNGRY HORSE	1.325	1.074
FLATHEAD LAKE	0.617	0.500
NOXON RAPIDS	0.000	0.000
PEND OREILLE LAKE	0.617	0.500
GRAND COULEE	5.664	4.592
BROWNLEE	0.023	0.019
DWORSHAK	1.052	0.853
JOHN DAY	2.220	0.180
TOTAL	27.264	22.103
Forecast of Adjusted Residual Runoff Volume	26.270	21.297
Computed Initial Control Flow from Chart 1 of Flood Control Operation Plan	5,663 m^3/s	200 kcfs

CHART 1
SEASONAL PRECIPITATION
COLUMBIA RIVER BASIN
OCTOBER 2000 SEPTEMBER 2001
PERCENT OF 1961 – 1990 AVERAGE

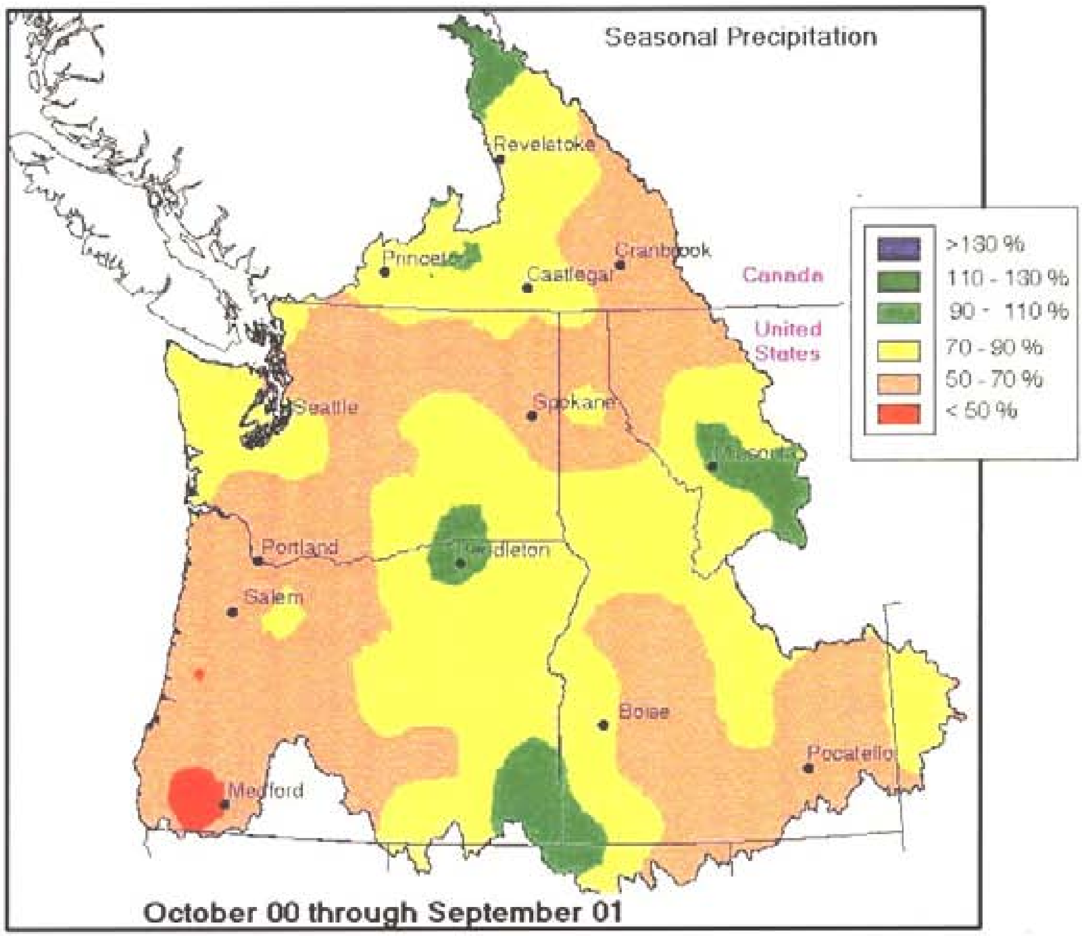
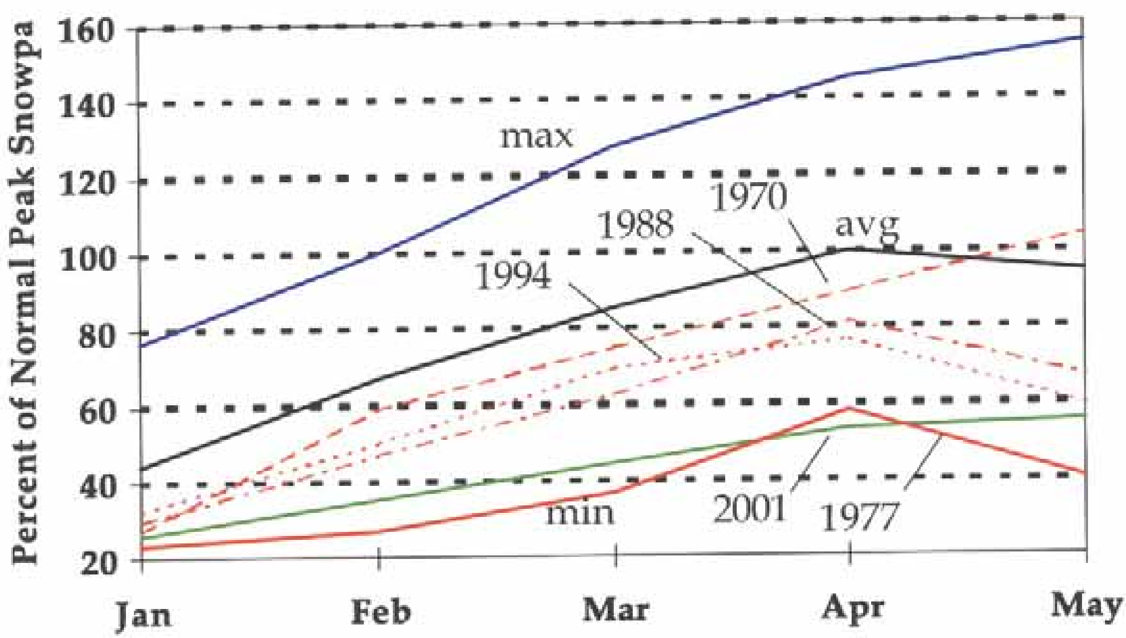


CHART 2
COLUMBIA BASIN SNOWPACK



ACCUMULATED PRECIP. FOR WY 2001
AT PRIMARY COL. RIVER BASINS

CHART 3

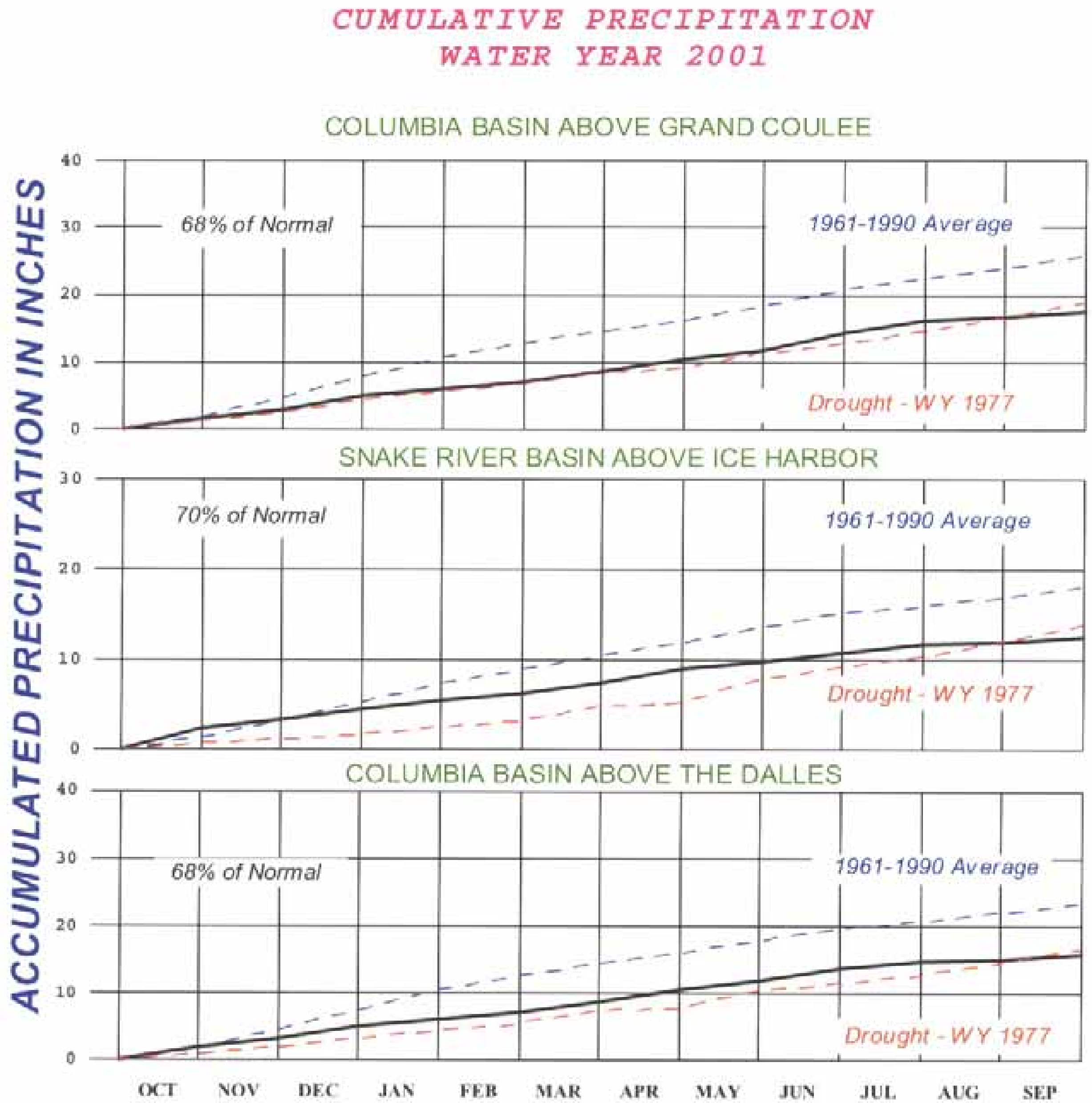
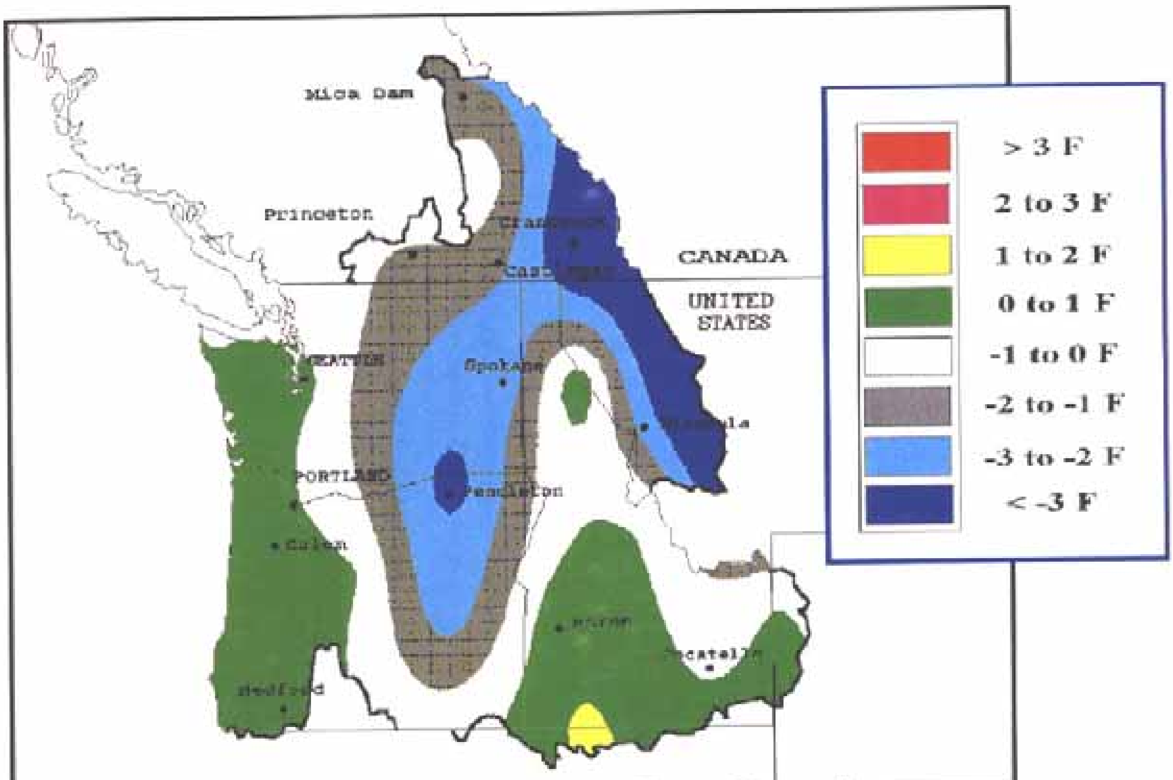
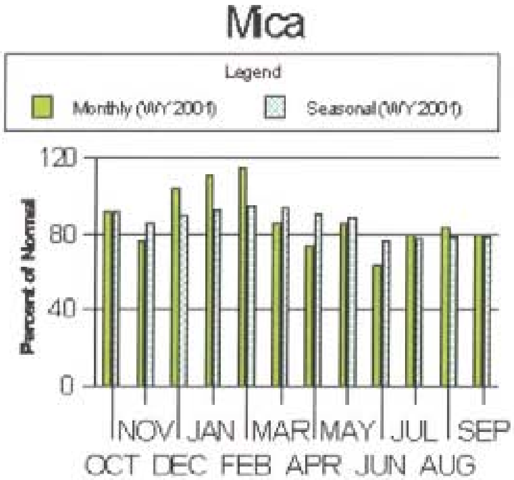


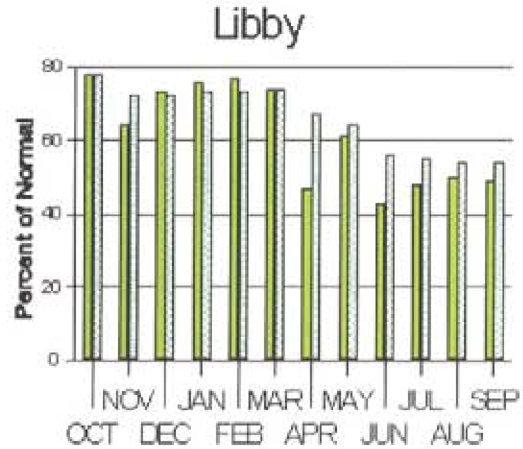
CHART 4
PACIFIC NORTHWEST MONTHLY TEMPERATURE DEPARTURES FROM NORMAL
DECEMBER 2000

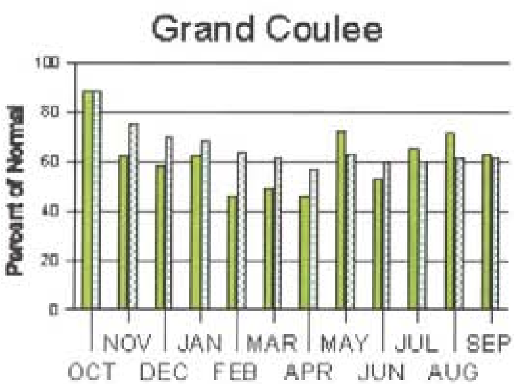


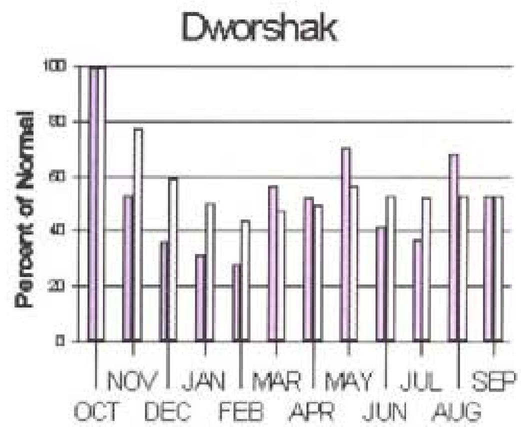
December 00 Temperature Departure From Normal

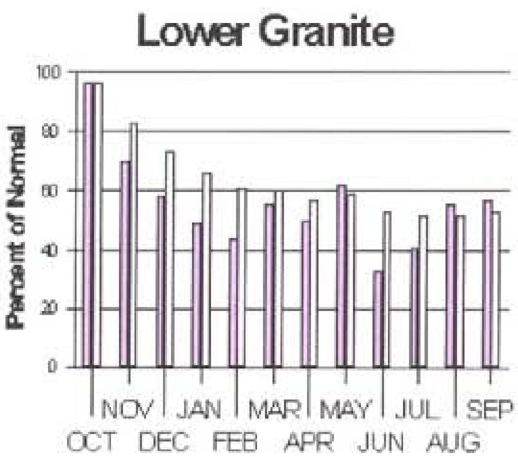
CHART 5
MONTHLY AND SEASONAL RESERVOIR INFLOW AT KEY INDICES
WATER YEAR 2001











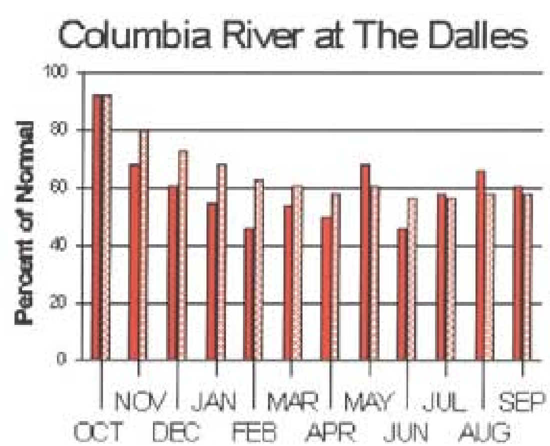
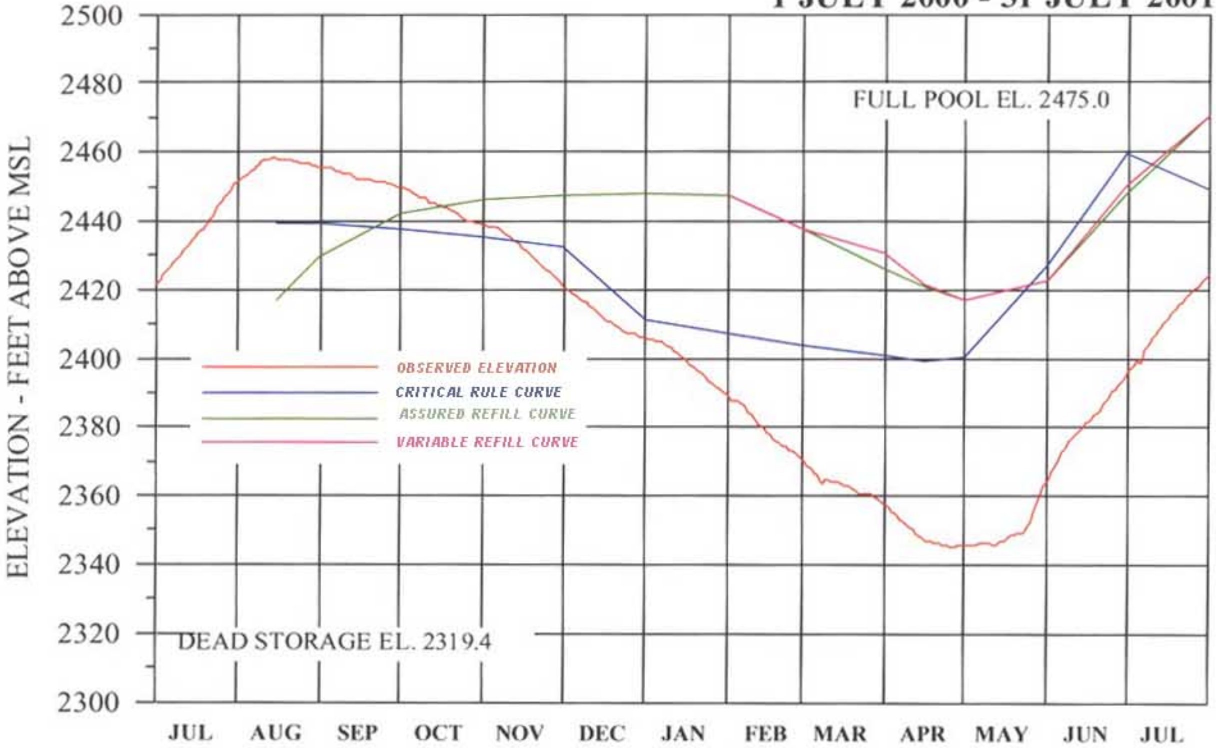


CHART 6
REGULATION OF MICA
1 JULY 2000 - 31 JULY 2001



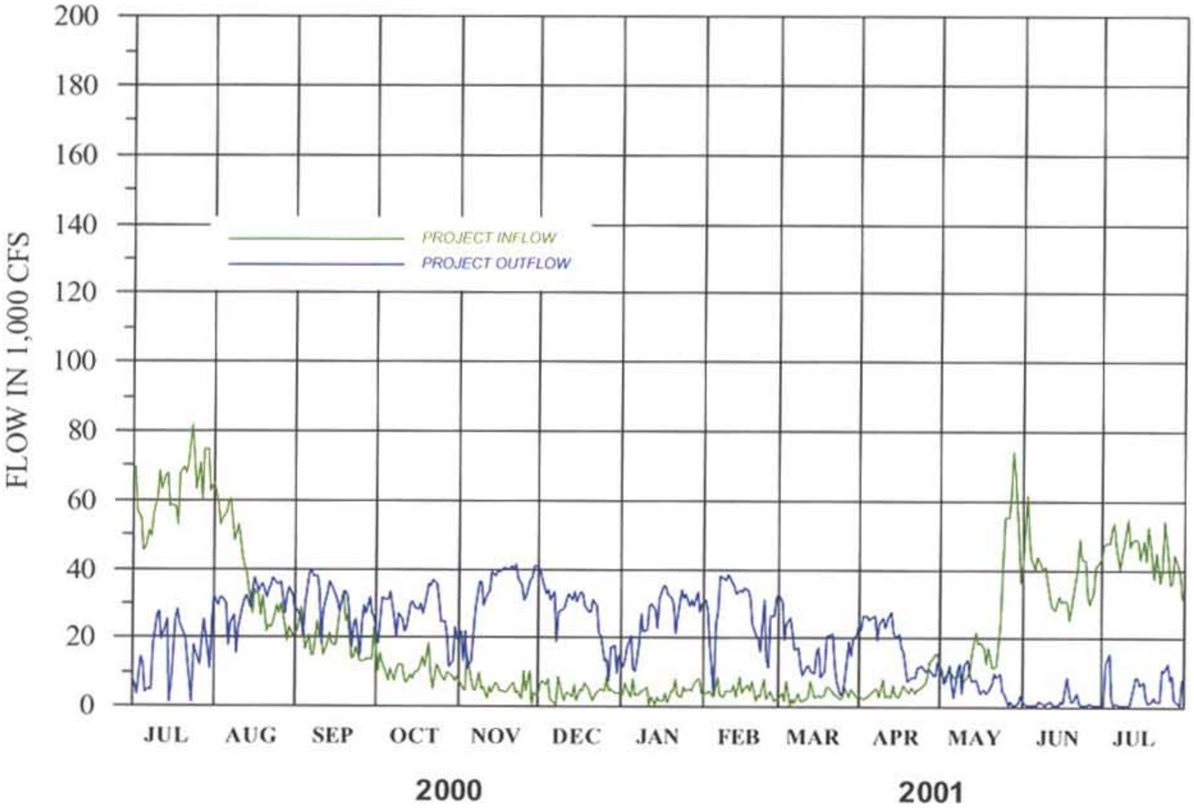


CHART 7
REGULATION OF ARROW
1 JULY 2000 - 31 JULY 2001

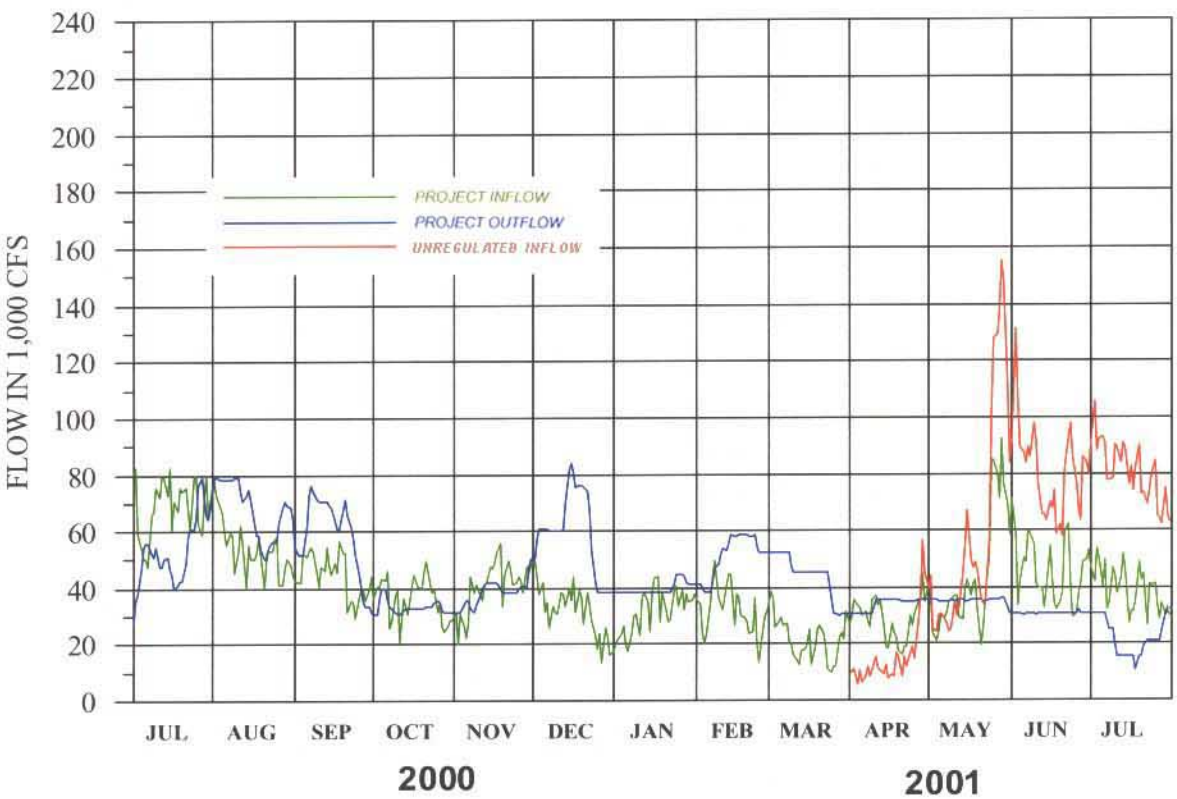
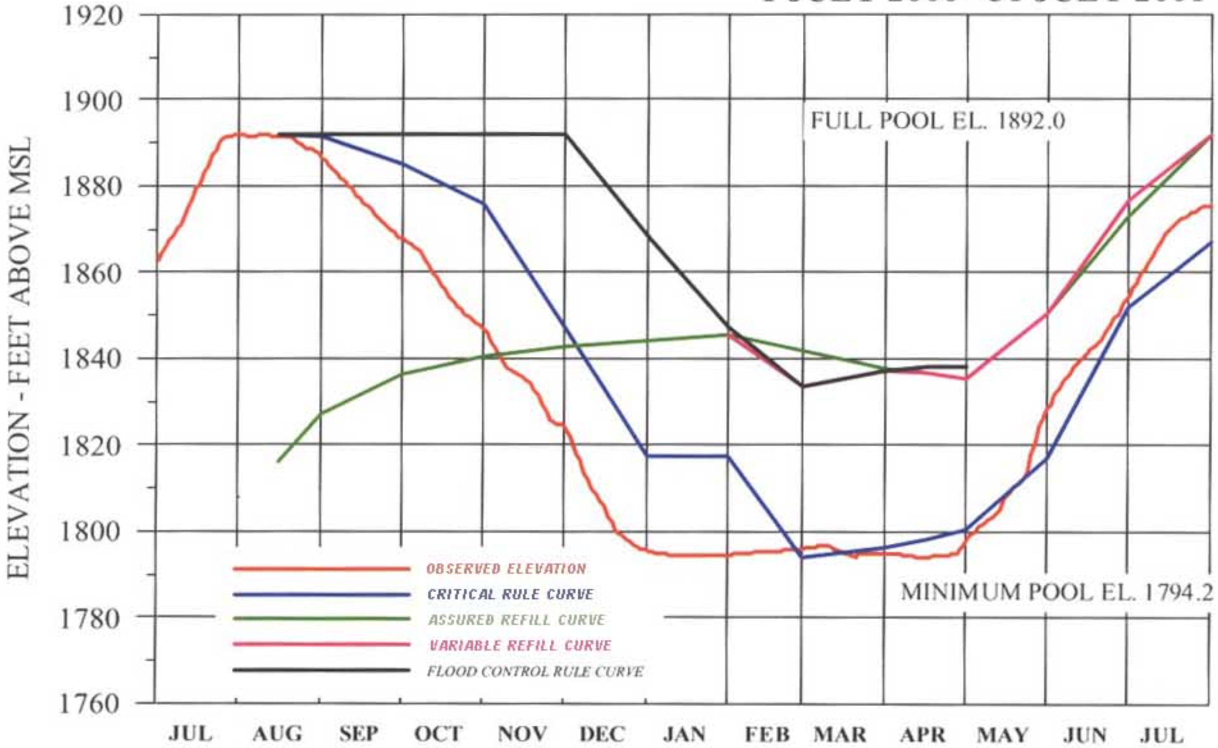


CHART 8
REGULATION OF DUNCAN
1 JULY 2000 - 31 JULY 2001



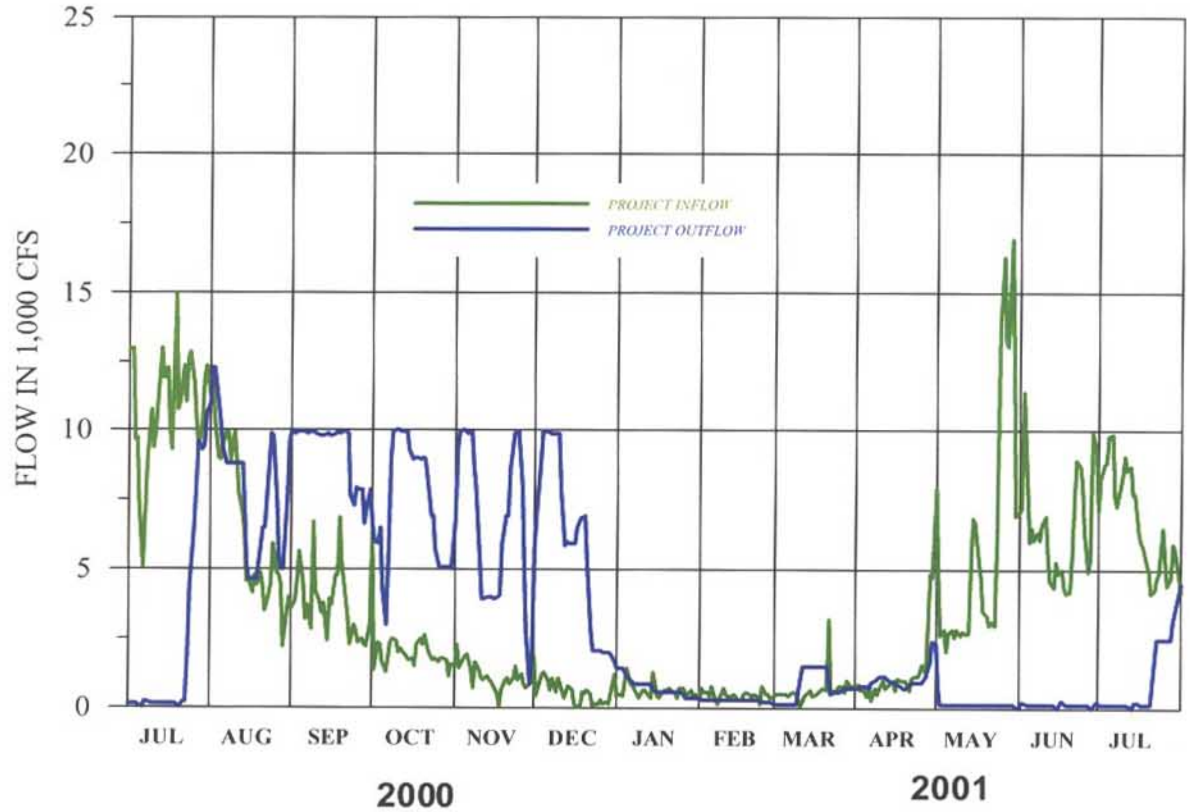
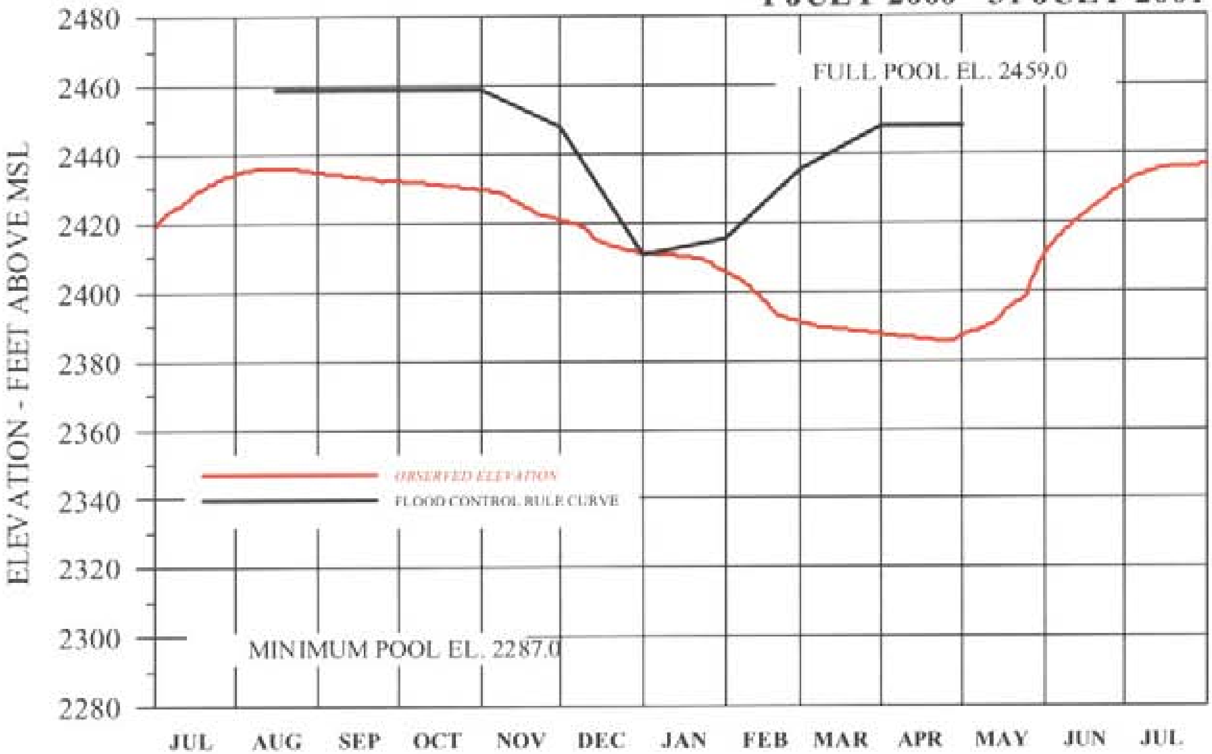


CHART 9
REGULATION OF LIBBY
1 JULY 2000 - 31 JULY 2001



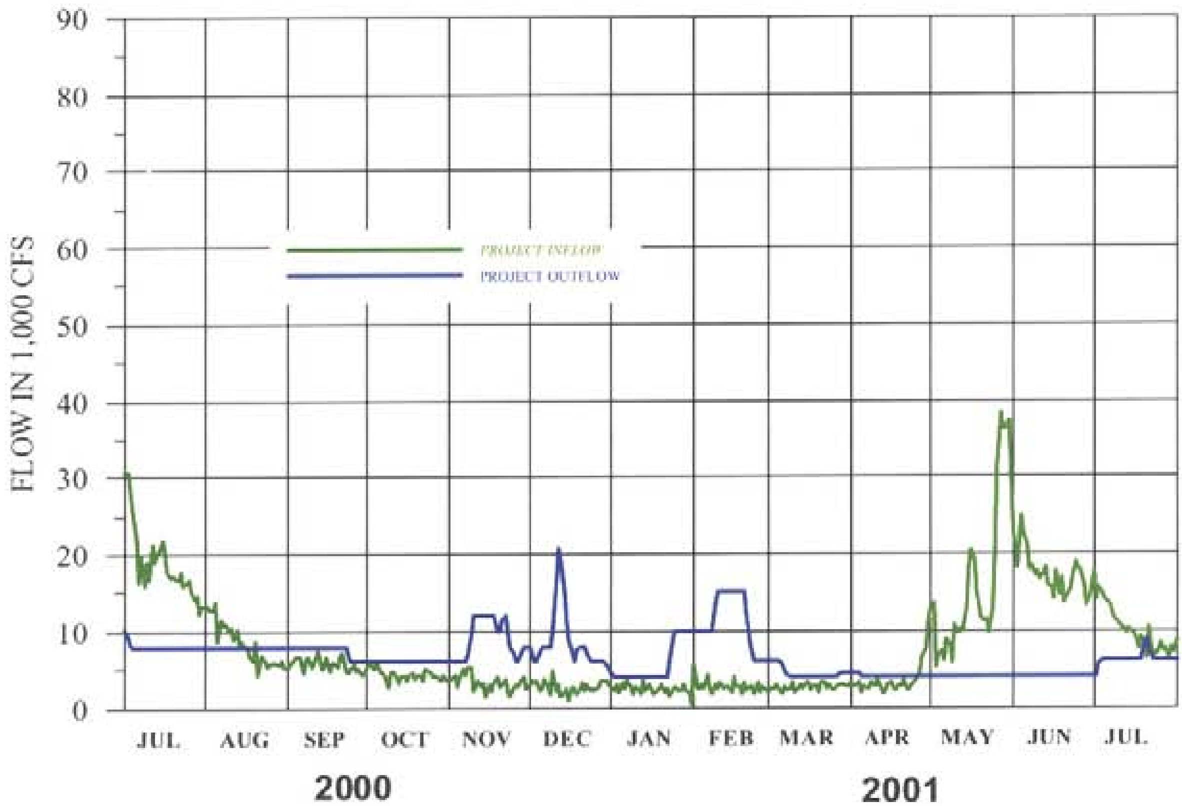
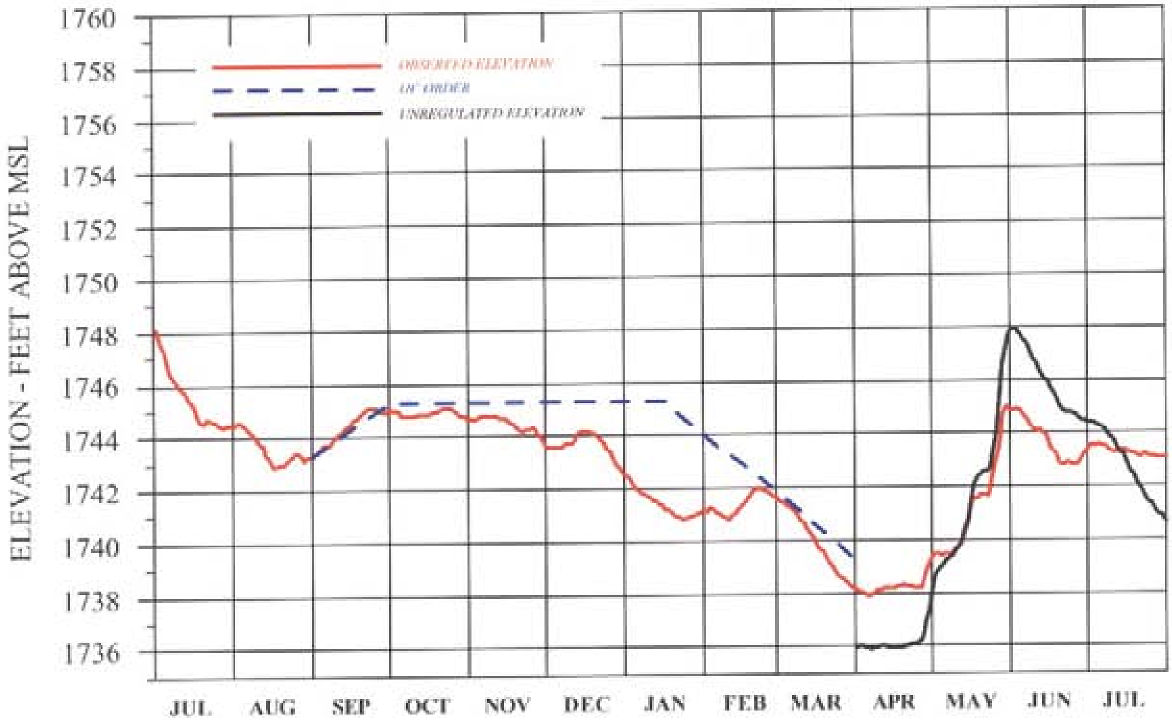


CHART 10
REGULATION OF KOOTENAY LAKE
1 JULY 2000 - 31 JULY 2001



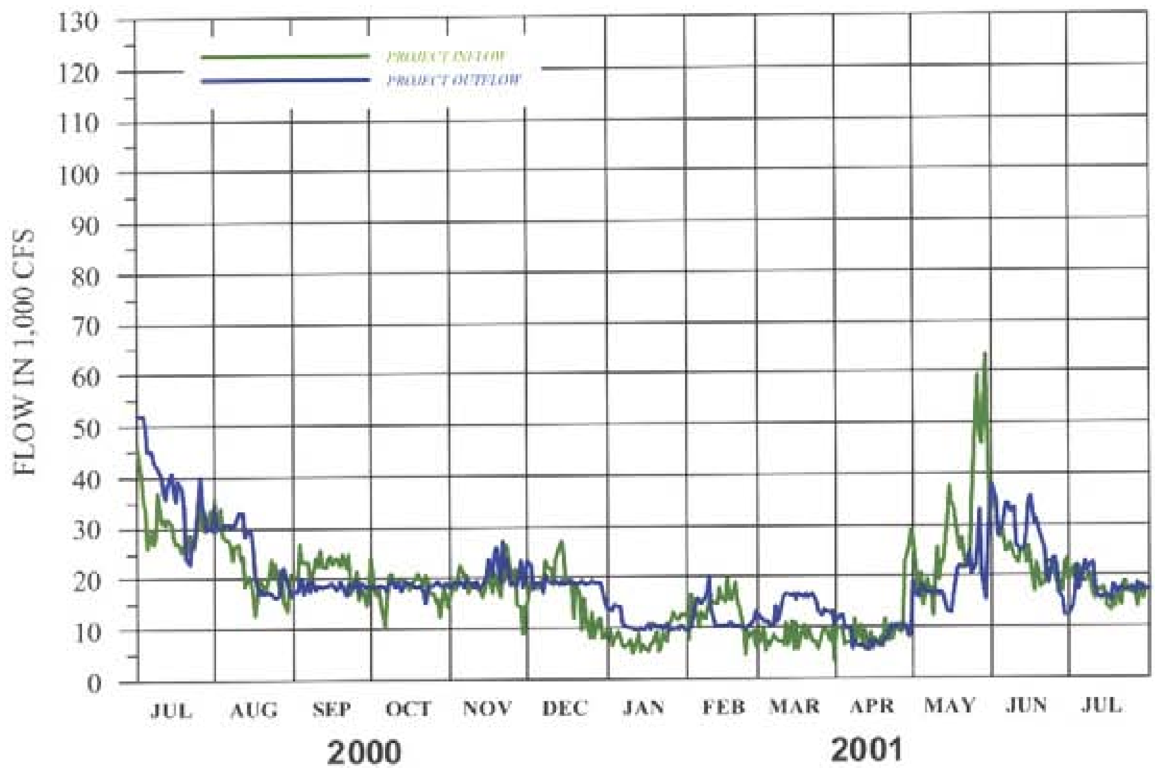


CHART 11
COLUMBIA RIVER AT BIRCHBANK
1 JULY 2000 - 31 JULY 2001

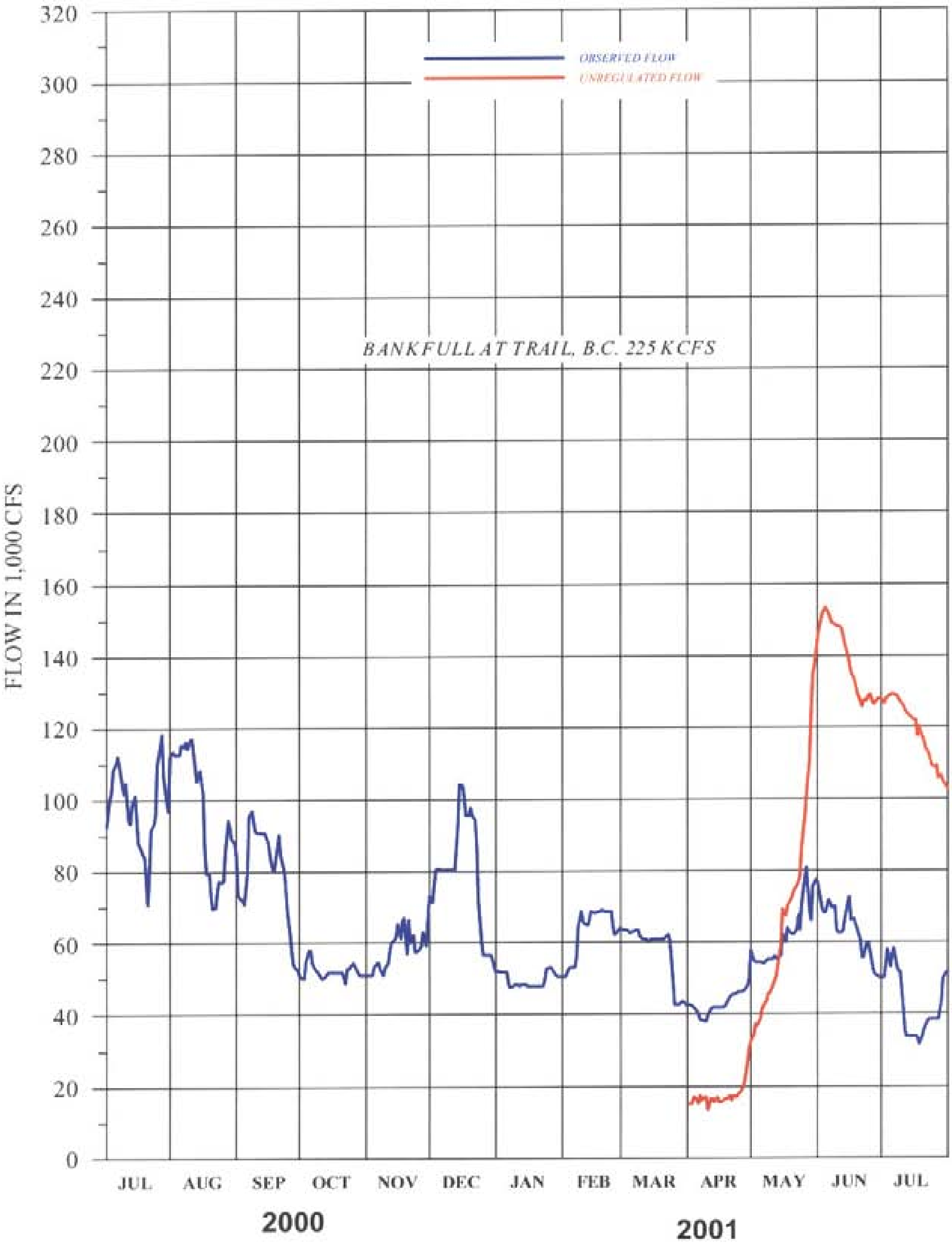
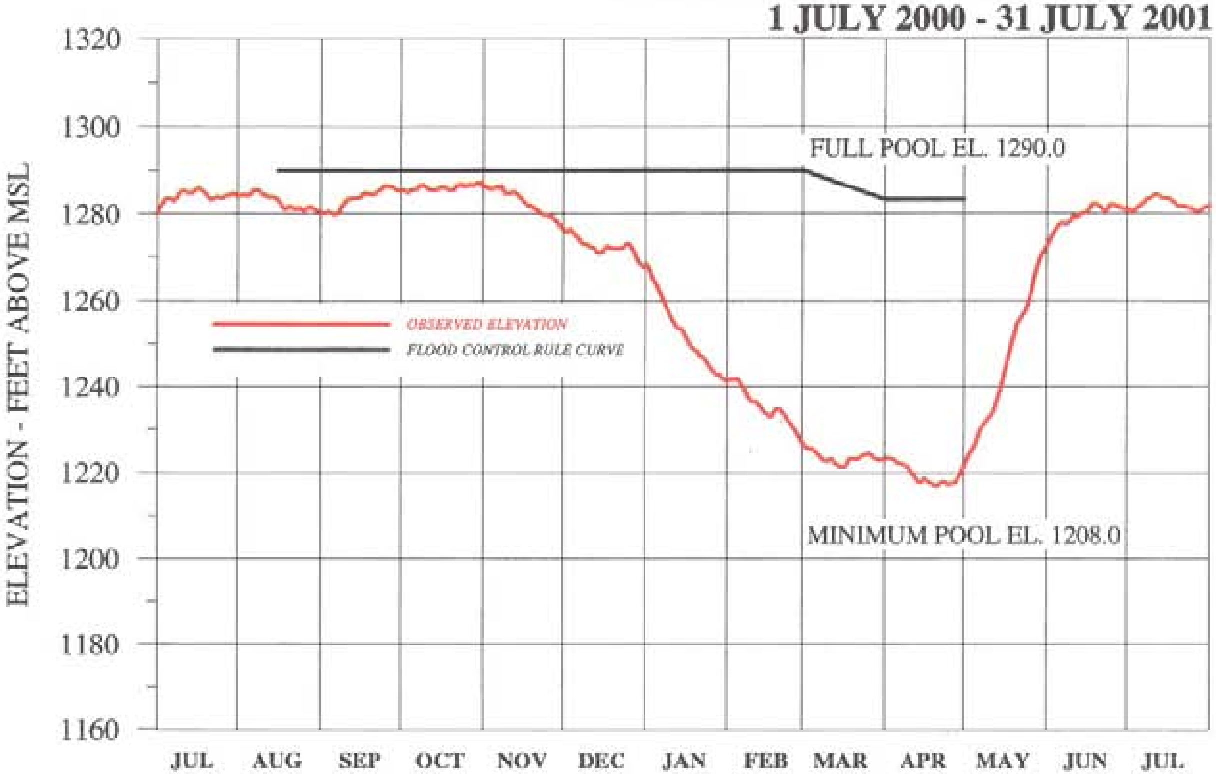


CHART 12
REGULATION OF GRAND COULEE
1 JULY 2000 - 31 JULY 2001



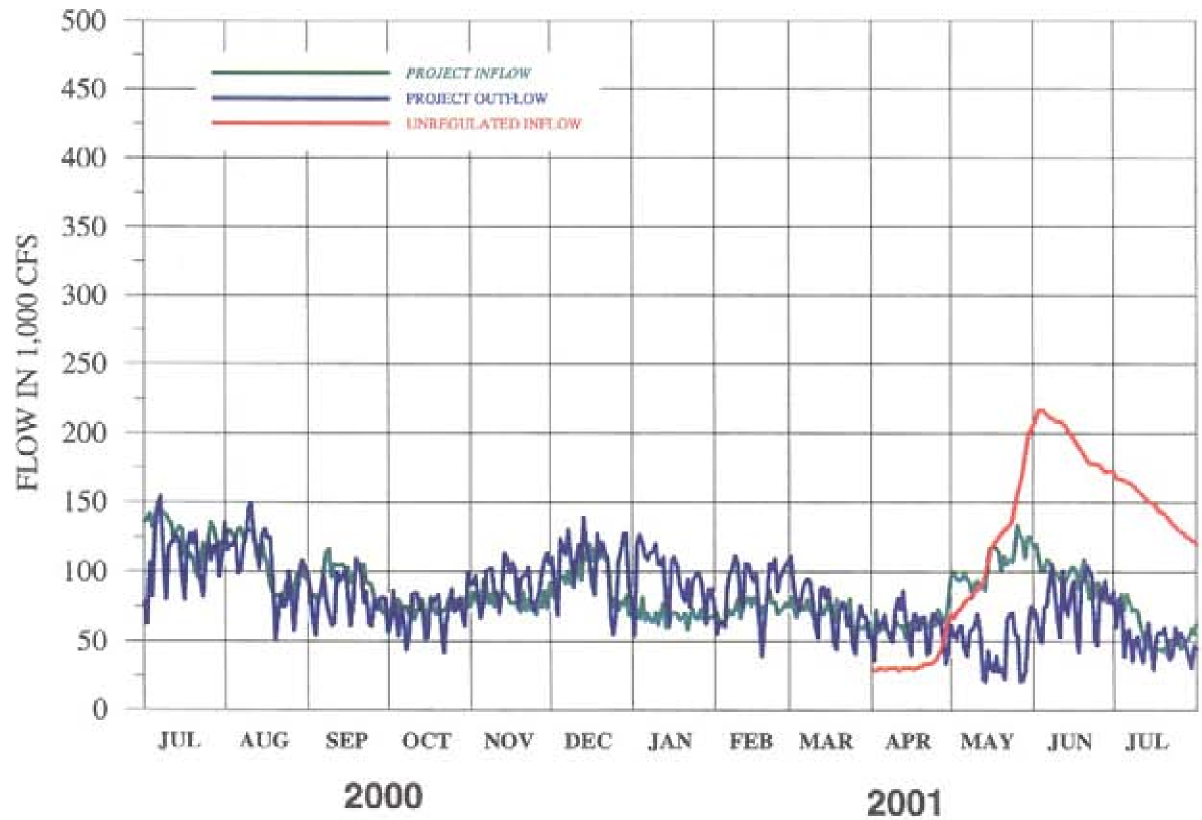


CHART13
COLUMBIA RIVER AT THE DALLES
1 JULY 2000 - 31 JULY 2001

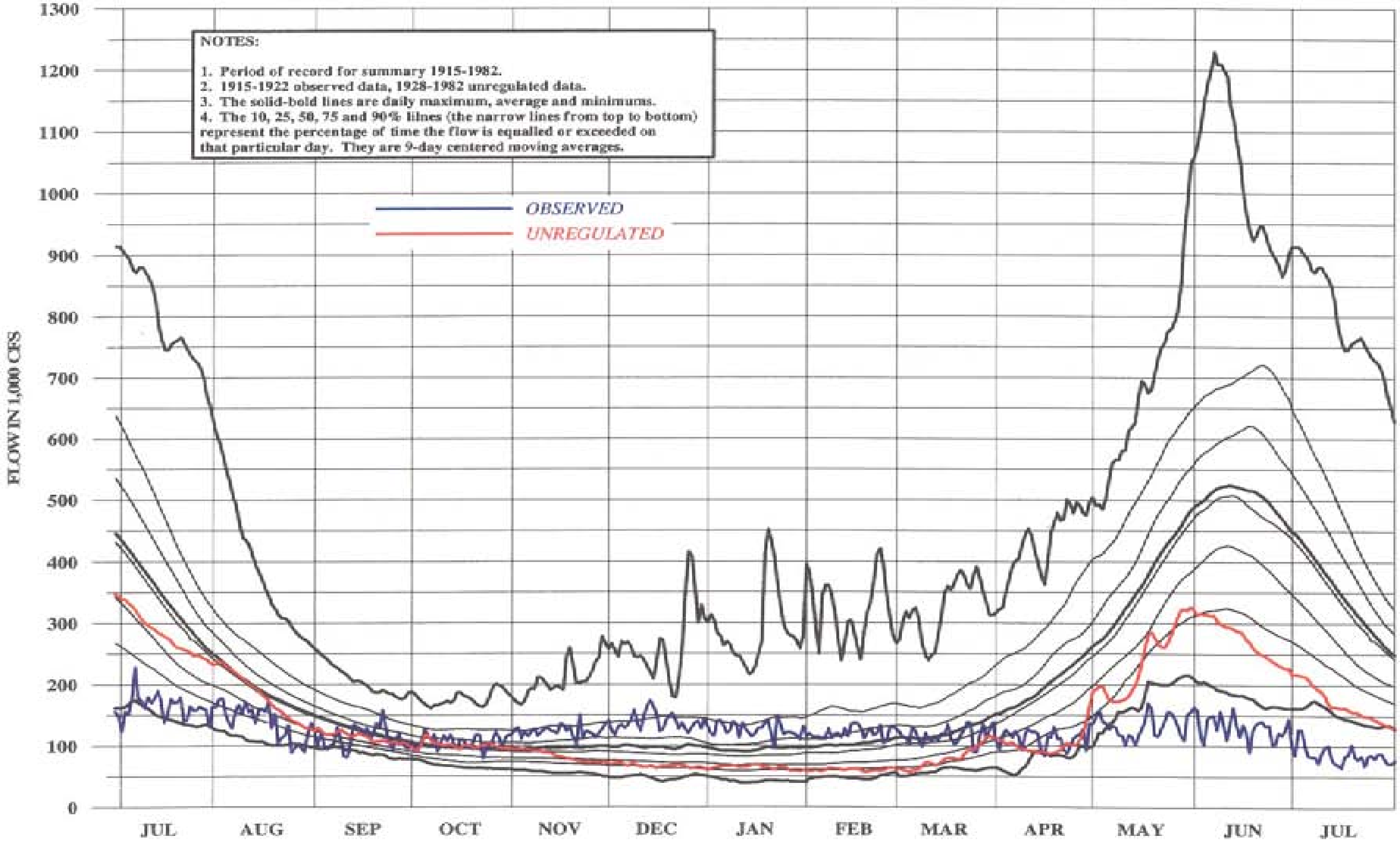


CHART 14
COLUMBIA RIVER AT THE DALLES
1 APRIL 2001 - 31 JULY 2001

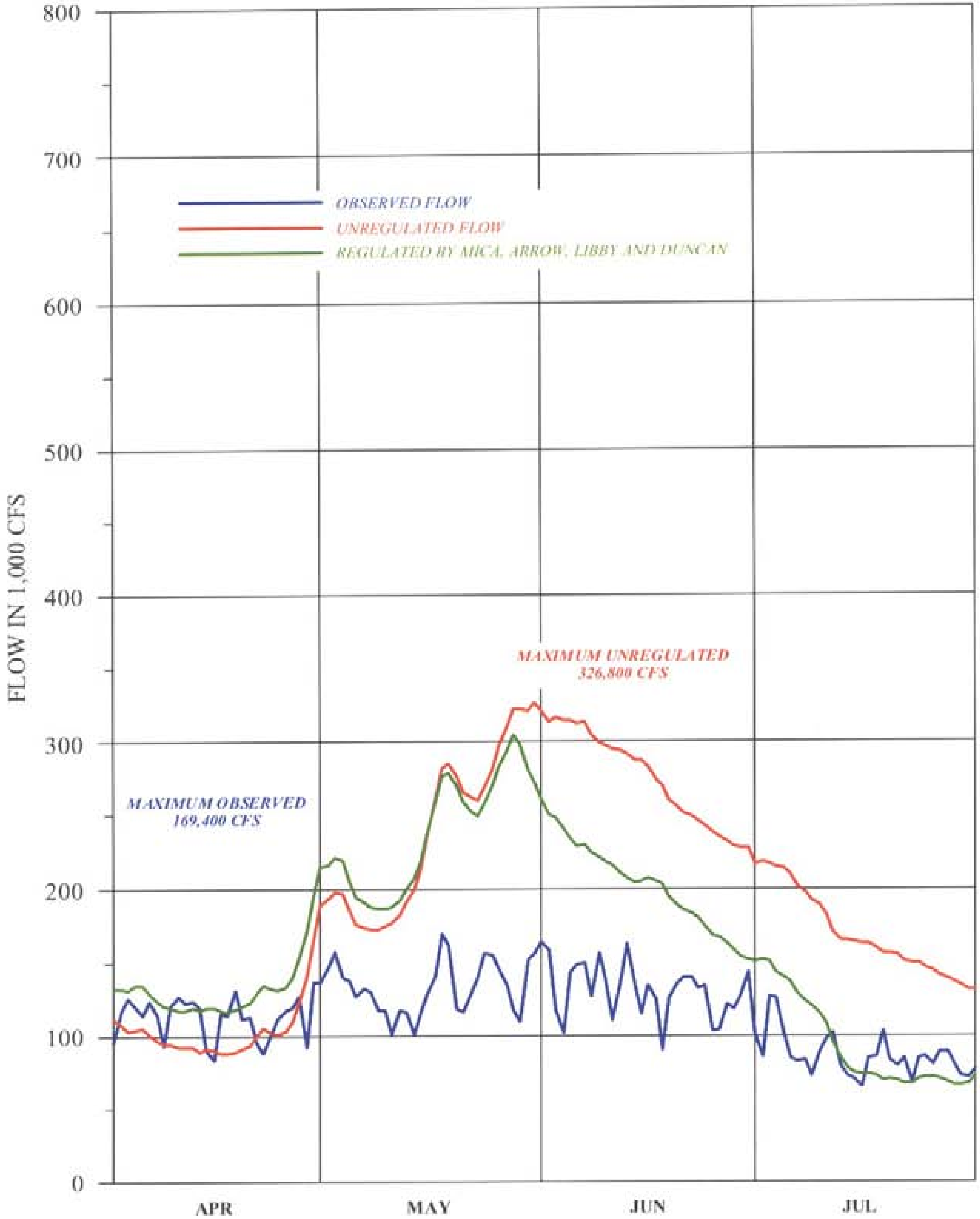


CHART 15
2001 RELATIVE FILLING
ARROW AND GRAND COULEE